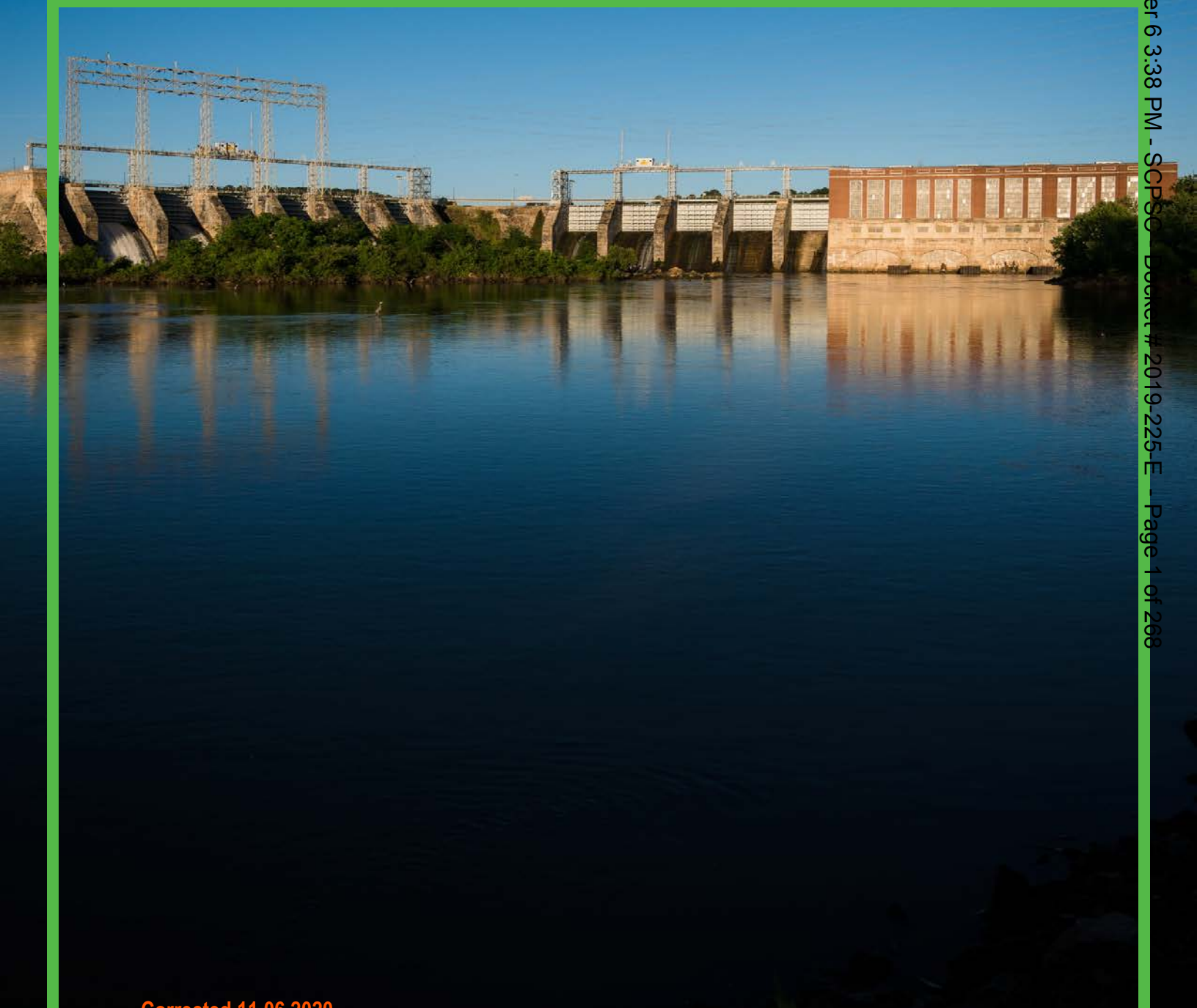


# APPENDICES



Corrected 11.06.2020



# QUANTITATIVE ANALYSIS

## APPENDIX A: QUANTITATIVE ANALYSIS

This appendix provides an overview of the Company's quantitative analysis of the resource options available to meet customers' future energy needs. An evaluation of the economic retirement dates of DEP's coal plants helped establish the starting point for the quantitative analysis discussed in this appendix. Sensitivities on major inputs informed the development of multiple portfolios that were then evaluated under nine scenarios that varied combinations of fuel prices and CO<sub>2</sub> constraints. These portfolios were analyzed, identifying trade-offs between cost and carbon reductions, while considering opportunities and barriers to enable the portfolio's transition. Each of these plans account for the cost to customers, resource diversity, reliability and the long-term carbon intensity of the system and any of the six portfolios presented are potential pathways depending on future federal and state policies and technology advancements and cost trajectories.

The future resource needs were optimized for DEP and DEC independently. However, an additional case representative of jointly planning future capacity on a DEP/DEC combined system basis using the Base Case assumptions was also analyzed to demonstrate potential customer savings, if this option was available in the future.

## OVERVIEW OF ANALYTICAL PROCESS

The analytical process consists of six steps:

1. Evaluate economic retirement dates of coal plants
2. Assess resource needs
3. Identify and screen resource options for further consideration
4. Develop base planning portfolio configurations and perform sensitivity analysis
5. Develop alternative portfolio configurations
6. Perform portfolio analysis over various scenarios

### 1. EVALUATE ECONOMIC SELECTION OF COAL PLANT RETIREMENT DATES

As discussed in Chapter 11, DEP conducted a detailed coal plant retirement analysis to determine the most economic retirement dates for each of the Company's coal assets. This analysis identified the retirement dates used in the Base Planning with Carbon Policy and Base Planning without Carbon Policy



for each of DEP’s coal plants. In addition to the economic retirement analysis, the Company also determined the earliest practicable retirement dates for each coal asset. The “earliest practicable” retirement date portfolio is discussed later in this appendix.

Through the process detailed in Chapter 11, following economic coal retirement dates were used in developing the base planning portfolios.

**TABLE A-1**  
**ECONOMIC RETIREMENT DATES OF DEP COAL PLANTS**

	2019 IRP RETIREMENT YEAR (JAN 1)	2020 IRP MOST ECONOMIC RETIREMENT ANALYSIS RETIREMENT YEAR (JAN 1)
Mayo 1	2036	2029
Roxboro 1 & 2	2029	2029
Roxboro 3 & 4	2034	2028

## 2. ASSESS RESOURCE NEEDS

The required load and generation resource balance needed to meet future customer demand was assessed as outlined below:

- **Customer peak demand and energy load forecast** – identified future customer aggregate demands to determine system peak demands and developed the corresponding energy load shape.
- **Existing supply-side resources** – summarized each existing generation resource’s operating characteristics including unit capability, potential operational constraints and projected asset retirement dates.
- **Operating parameters** – determined operational requirements including target planning and operational reserve margins and other regulatory considerations.



Customer load growth, the expiration of purchased power contracts and additional asset retirements result in resource needs to meet energy and peak demands in the future. The following assumptions impacted the 2020 resource plan:

- **Peak Demand and Energy Growth** - The growth in winter customer peak demand after the impact of energy efficiency averaged 0.8% from 2021 through 2035. The forecasted compound annual growth rate for energy is 0.7% after the impacts of energy efficiency programs are included.
- **Planned Generation Upgrades and Additions** –
  - Nuclear upgrades totaling 20 MW
- **Combustion Turbine Retirements** –
  - Weatherspoon 1-4 CTs assumed to retire in 2026
  - Blewett CTs assumed to retire in 2026
- **Expiring purchase contracts** are assumed to be replaced with like-kind purchase power contracts
- **Reserve Margin** - A 17% minimum winter planning reserve margin for the planning horizon

### 3. IDENTIFY AND SCREEN RESOURCE OPTIONS FOR FURTHER CONSIDERATION

The IRP process evaluated EE, DSM and traditional and non-traditional supply-side options to meet customer energy and capacity needs. The Company developed EE and DSM projections based on existing EE/DSM program experience, the 2020 market potential study, input from its EE/DSM collaborative and cost-effectiveness screening for use in the IRP. Supply-side options reflect a diverse mix of technologies and fuel sources (gas, nuclear, renewable, and energy storage). Supply-side options are initially screened based on the following attributes:

- Technical feasibility and commercial availability in the marketplace
- Compliance with all Federal and State requirements
- Long-run reliability
- Reasonableness of cost parameters

The Company compared the capacity size options and operational capabilities of each technology, with the most cost-effective options of each being selected for inclusion in the portfolio analysis phase. An overview of resources screened on technical basis and a levelized economic basis is discussed in Appendix G.

## RESOURCE OPTIONS

### ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT





EE and DSM programs continue to be an important part of Duke Energy Progress' system mix. The Company considered both EE and DSM programs in the IRP analysis. As described in Appendix D, EE and DSM measures are compared to generation alternatives to identify cost-effective EE and DSM programs.

The base planning assumptions for EE and DSM portfolios incorporates projected program adoption rates, and costs based on a combination of both internal company expectations, inclusive of current programs, and projections based on information from the 2020 market potential study. The program costs used for this analysis leveraged the Company's internal projections for the first five years and in the longer term, utilized the updated market potential study data incorporating the impacts of customer participation rates over the range of potential programs. Additionally, the Company included the impacts on energy and winter peak demand from the addition of an IVVC peak shaving program discussed in Appendix D.

Over the 15-year planning horizon, EE and DSM programs, including the new IVVC program discussed in Appendix D, are expected to provide over 830 MW of winter peak demand reduction in the base planning scenarios.

### SUPPLY-SIDE

The following technologies were included in the quantitative analysis as potential supply-side resource options to meet future capacity needs:

DEC DISPATCHABLE (WINTER RATINGS)			
			
BASELOAD	PEAKING / INTERMEDIATE	STORAGE	RENEWABLE NON- DISPATCHABLE (WINTER RATINGS)
1,224 MW, 2x2x1 Advanced Combined Cycle (Duct Fired, No Inlet Chiller)	913 MW, 4 x 7FA.05 Combustion Turbines (CTs)	50 MW / 200 MWh Lithium-ion Battery	150 MW Onshore Wind
684 MW, 12 Small Modular Reactor Nuclear Units (NuScale)		50 MW / 300 MWh Lithium-ion Battery	600 MW Offshore Wind
21 MW – Combined Heat & Power (Combustion Turbine)		1,400 MW Pumped Storage Hydro (PSH)	75 MW Fixed-Tilt (FT) Solar PV
			75 MW Single Axis Tracking (SAT) Solar PV
			75 MW SAT Solar PV plus 20 MW / 200 MWh Lithium-ion Battery



#### 4. DEVELOP BASE PLANNING PORTFOLIO CONFIGURATIONS AND PERFORM SENSITIVITY ANALYSIS

The step is broken down into three sections. The first section discusses the key variables in portfolio development and those considered in sensitivity and portfolio analysis. The second discusses the Base Planning portfolio development and results. The final section details the overall quantitative analysis of the individual sensitivity screening cases that were analyzed in the sensitivity analysis to inform the development of the alternative portfolios.

##### VARIABLES CONSIDERED IN SENSITIVITY & PORTFOLIO ANALYSIS

The Company uses base planning assumptions for the development of the base cases. However, the Company also conducted sensitivity analysis of various drivers using the expansion planning simulation modeling software, *System Optimizer* (SO). The expansion plans from these sensitivities produced by SO were then processed through the more detailed hourly production cost model, PROSYM to provide production costs for each of the expansion plans. The results of the sensitivity analysis were used to inform the development of the alternative portfolios presented in the IRP. Each of the base planning and alternative portfolios were analyzed under combinations of fuel and carbon tax trajectories in PROSYM in order to compare the Present Value of Revenue Requirements (PVRR) of each portfolio under the various scenarios, as well as, develop an estimate of average residential monthly bill impact of implementing the various portfolios under base planning assumptions. An overview of the key variable assumptions for the development of the base cases and for the Sensitivity and Scenario Analyses considered in both SO and PROSYM are outlined below:

##### LOAD FORECAST

DEP modeled the impacts of changes to the load forecast on the expansion plans. The Company based these sensitivities on the near-term growth and recession scenarios provided by Moody's Analytics. The impacts to the load forecast are summarized below:

**TABLE A-2**  
**LOAD FORECAST SENSITIVITY PARAMETERS**

	LOW	BASE	HIGH
2035 Winter Peak Demand, MW	15,830	15,966	16,086
2035 Annual Energy, MWh	69,797,797	70,446,299	70,983,725

## IMPACT OF POTENTIAL CARBON CONSTRAINTS

The base CO<sub>2</sub> price was developed to incentivize less carbon intensive resources on the path to net zero carbon by 2050. Based on the earliest expected time to propose, pass and implement legislation or regulation the CO<sub>2</sub> price is set to begin in 2025. Ultimately, the CO<sub>2</sub> price will likely be dependent on many factors such as fuel and technology cost, tax incentives as well as pace of reduction goals.

In the 2019 IRP, the CO<sub>2</sub> price also started in 2025 at 5 \$/ton and escalated at a rate of \$3/ton per year, which incentivized CO<sub>2</sub> reductions of 60 to 70% by 2050 from a 2005 baseline. However, the price was not high enough to incentivize zero-emitting load-following resources (ZELFR) such as nuclear, hydrogen fueled generation or carbon capture and sequestration in lieu of natural gas generation prior to 2050.

In September 2019, after the filing of the 2019 IRP, Duke Energy announced an enterprise wide CO<sub>2</sub> reduction goal of at least 50% by 2030 and to be net zero carbon by 2050. In addition to accelerating coal retirements, additional renewables and storage, there is a need for ZELFR technologies in 2035 to 2050 timeframe to facilitate the replacement of remaining coal generation and existing natural gas combined cycle generation as they meet their projected retirement dates. The company's analysis showed a CO<sub>2</sub> price starting at \$5/ton in 2025 increasing at a rate of \$5/ton per year incentivized ZELFR technology in the 2040 to 2050 timeframe, where increasing at a rate of \$7/ton accelerated the selection of ZELFRs in the 2035 to 2040 timeframe. Both the \$5 and \$7/ton per year price incentivize battery storage to meet a portion of new peaking need by 2030, additional renewables, accelerated coal retirements and limiting dispatch of carbon emitting generation.

There have been multiple federal legislative proposals that Duke has been tracking including:

**Climate Leadership Council** – \$40/ton escalating at 5% per year

**CLEAN Futures Act** – A Clean Electricity Standard (CES) that incentivized similar reductions to \$5/ton escalating at \$7/ton per year

**Energy Innovation and Carbon Dividend Act (H.R. 763)** – \$15/ton escalating at \$10/ton per year

**American Opportunity Carbon Free Act of 2019 (S. 1128)** – \$52/ton escalating at 8.5% per year

The Climate Leadership Council and CLEAN Futures Act each drive a similar pace of carbon reduction as the \$5/ton and \$7/ton per year carbon price trajectories. The higher CO<sub>2</sub> prices associated with H.R. 763 and S. 1128 would drive retirement of coal and gas generation at a faster pace which would accelerate the need for ZELFRs prior to 2035. However, the pace of CO<sub>2</sub> reduction would be limited by the amount of renewables and storage that could be interconnected in a given year, technological development and deployment of storage and ZELFRs technologies and the impact on customer rates.

In consideration of the mentioned legislative proposals and consistent with Duke Energy's CO<sub>2</sub> reduction goal, the Reference 2020 CO<sub>2</sub> price is \$5/ton starting in 2025 escalating at a rate of \$5/ton per year. This CO<sub>2</sub> price trajectory incentivizes the continued adoption of renewables, storage, accelerated coal retirements which supports a path to net zero by 2050. When comparing alternative plans the inclusion of the CO<sub>2</sub> price in the overall project economics would be reflective of a carbon tax, and if excluded, would be reflective of a CO<sub>2</sub> mass cap or cap and trade with allowance allocations.

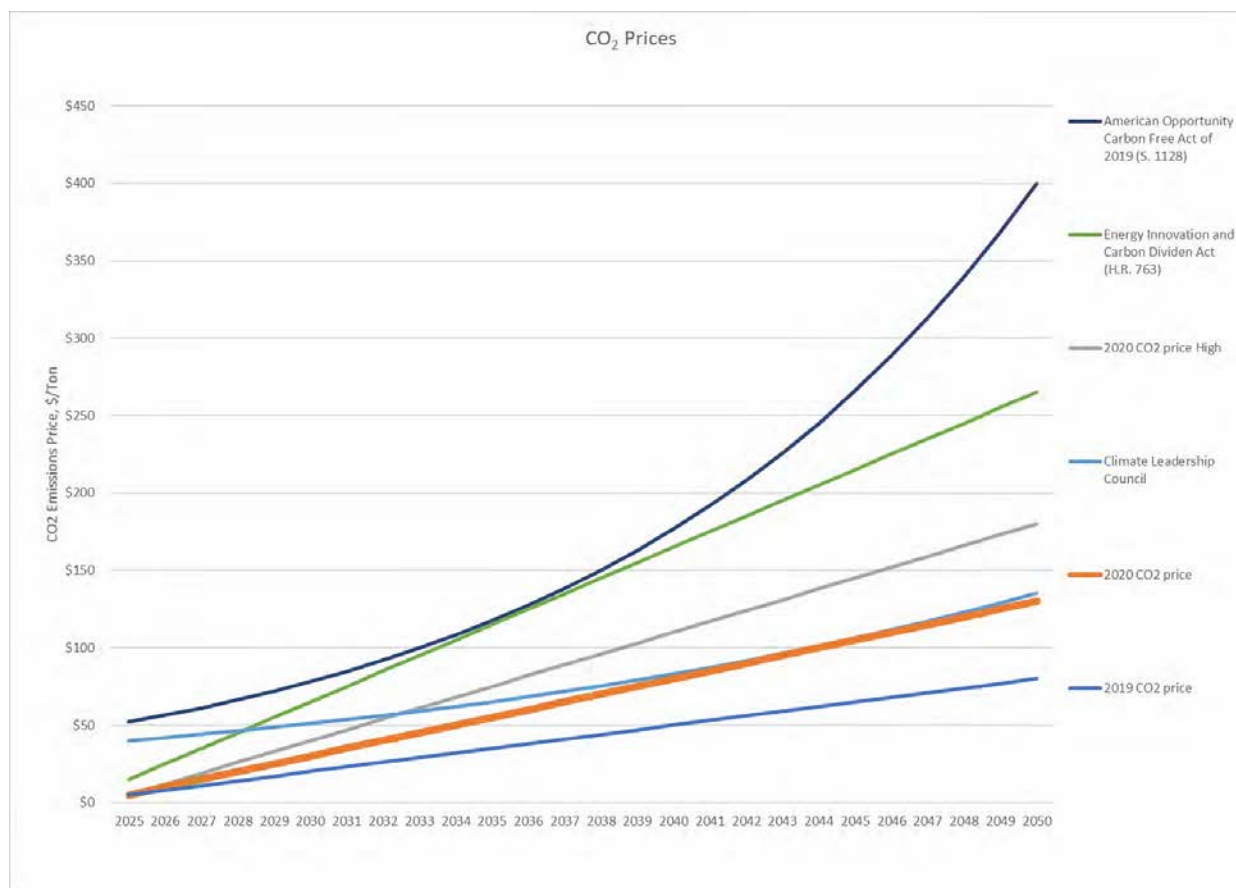
**Base CO<sub>2</sub> Price** – \$5/ton in 2025 and escalating at \$5/ton annually applied to all stack carbon emissions.

**High CO<sub>2</sub> Price** – \$5/ton in 2025 and escalating at \$7/ton annually applied to all stack carbon emissions.



FIGURE A-1

## COMPARISON OF CO<sub>2</sub> PRICES AND OTHER CO<sub>2</sub> REFERENCE PRICES



## COAL PLANT RETIREMENT DATES

As described in Chapter 11, DEP evaluated the economic coal retirement dates for each coal plant. These dates were used in the base planning cases presented in the IRP. Additionally, DEP determined the earliest practicable retirement dates for each plant which contemplated the earliest date, setting aside normal economic considerations, that each coal plant could be retired but still giving consideration to the time it would take to place replacement resources into service. While the earliest practicable dates are technically feasible it would likely take supporting policy to effectuate such an aggressive retirement schedule. The complexities in the siting, permitting, construction and regulatory approvals for such a large amount of replacement resources in a short period of time would, in all likelihood, not be feasible without new supporting policy. This is emphasized when taking into

account the fact that the combined DEC/DEP systems would simultaneously be retiring all coal units prior to 2030 or in the case of Cliffside unit 6 cease burning coal by 2030 limiting future operations to entirely natural gas in this scenario. The earliest practicable coal retirement dates and additional considerations are discussed later in this appendix.

## ENERGY EFFICIENCY

DEP modeled the adoption rate and program cost associated with EE based on a combination of both internal company expectations and projections based on information from the 2020 market potential study. Table A-3 provides the base, enhanced, and low EE MW and MWh impacts by 2035 including measures added in 2020 and beyond.

**TABLE A-3**  
**EE SENSITIVITY ANALYSIS PARAMETERS**

	LOW	BASE	HIGH
2035 Winter Peak EE, MW	182	243	487
2035 Annual EE, MWh	1,192,739	1,590,318	1,780,573

## DEMAND SIDE MANAGEMENT & IVVC

As discussed previously, DEP modeled the adoption rate and program cost associated with DSM based on a combination of both internal company expectations and projections based on information from the 2020 market potential study. Additionally, the Company included the peak shaving capability of DEP's IVVC program which provides a reduction to winter peak demand and overall energy consumption. Table A-4 provides the base, enhanced, and low DSM MW impacts by 2035 including measures added in 2020 and beyond. The base case was derived directly from the market potential study, while the enhanced case incorporated the market potential study and impacts associated with potential rate design demand response programs. The low case is simply a 25% reduction in adoption and cost impacts of DSM programs. The base IVVC program impacts are included in all three sensitivities.

**TABLE A-4**  
**DSM SENSITIVITY ANALYSIS PARAMETERS**

	LOW	BASE	HIGH
2035 Winter Peak DSM, MW	468	589	1,011

## SOLAR, SOLAR + STORAGE, AND WIND GENERATION

Three levels of renewable generation were evaluated as discussed in Appendix E. Each level included varying assumptions regarding penetration of solar and solar plus storage, wind availability, and annual interconnection limits. As discussed further in Appendix E, the base case includes renewable capacity components of the Transition MW, such as capacity required for compliance with NC REPS, PURPA purchases, the SC DER Program, NC Green Source Rider (pre HB 589 program), and the additional three components of NC HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). The Base Case also includes additional projected solar growth beyond NC HB 589, including expected growth from SC Act 62 and the materialization of additional projects in the transmission and distribution queues. The Base Case does not attempt to project future regulatory requirements for additional solar generation, such as new competitive procurement offerings after the current CPRE program expires.

In addition to the base case, a high and low case were developed. These portfolios do not envision a specific market condition, but rather the potential combined effect of a number of factors. For example, the high sensitivity could occur given events such as high carbon prices, lower solar capital costs, economical solar plus storage, continuation of renewable subsidies, and/or stronger renewable energy mandates. Additionally, the high case also considers a combination of onshore and offshore wind as viable resources beginning in the 2030 timeframe. On the other hand, the low sensitivity may occur given events such as lower fuel prices for more traditional generation technologies, higher solar installation and interconnection costs, and/or high ancillary costs which may drive down the economic viability of future incremental solar additions. These events may cause solar projections to fall short of the Base Case if the CPRE, renewable energy procurement for large customers, and/or the community solar programs of HB 589 do not materialize or are delayed



In all three cases, incremental solar plus storage and onshore Carolinas wind were available for selection in the capacity expansion model. However, the annual amount of solar plus storage that could be selected in each case was limited. Additionally, as discussed in Appendix E (Renewables) standalone solar was not available for selection by the capacity expansion model due to increasing levels of solar curtailment on the DEP system. Table A-5 details the differences between the inputs of the three renewable cases.

**TABLE A-5**  
**RENEWABLES SENSITIVITY ANALYSIS PARAMETERS**

	LOW	BASE	HIGH
Forced Solar by 2035, Nameplate MW	3,948	4,575	6,481
Forced Central US Wind by 2035, MW	0	0	422
Forced Offshore Carolinas Wind by 2035, MW	0	0	92
Allowed Solar coupled w/ Storage Annually, MW/Year	125	200	400
Allowed Onshore Carolinas Wind Annually, MW/Year	150	150	150

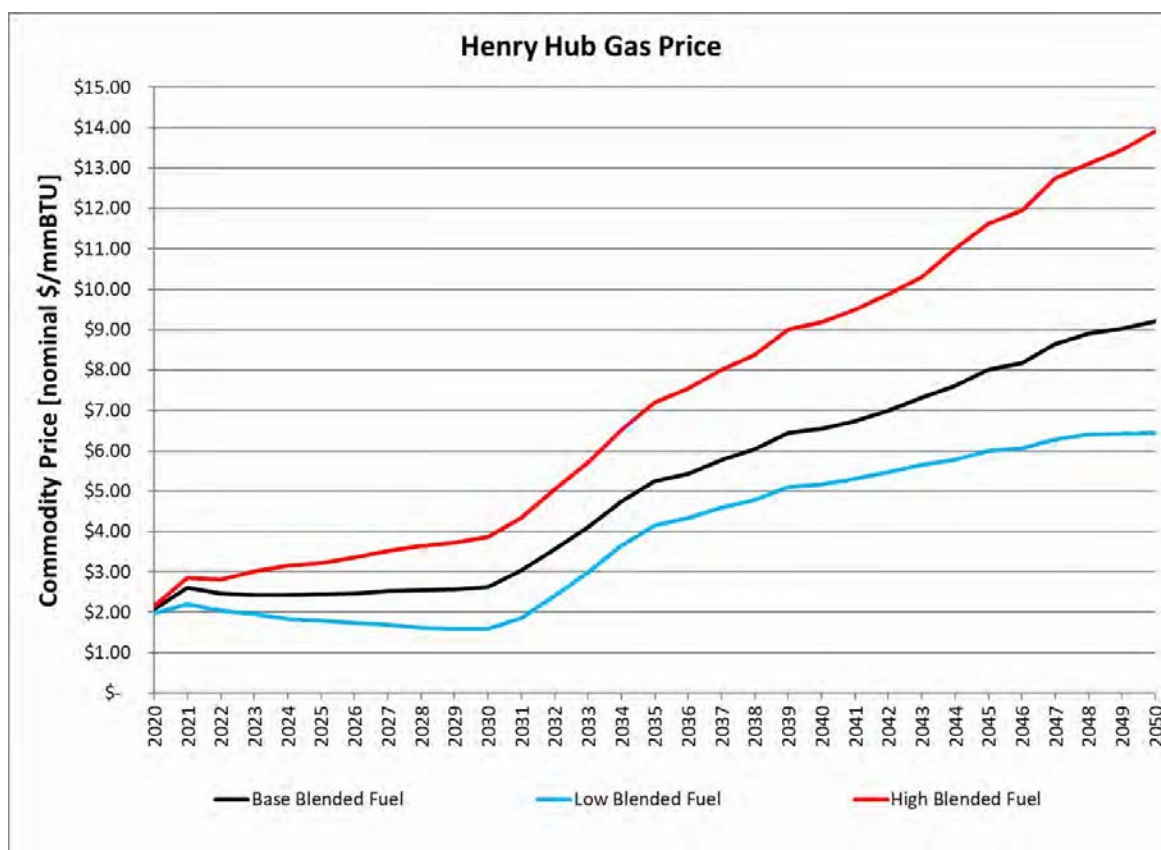
Additionally, as described in Chapter 7, transmission upgrade costs associated with interconnecting these distributed resources was estimated. These costs were applied after the technology was selected and are included in the PVRR and average residential bill impacts discussed later in this appendix.

## FUEL PRICES

DEP continues to rely on 10-year market purchases of natural gas and 5-years of market observations of coal prices before transitioning to fundamental fuel forecasts for development of the IRP.

- Natural Gas based on market prices from 2021 through 2030 transitioning to 100% fundamental by 2035.
- Coal based on market observations through 2024 transitioning to 100% fundamental by 2030. In order to test the effects of changing fuel prices on resource selection and portfolio value, DEP developed high and low natural gas prices. By only changing natural gas prices, the impact on resource selection (CC vs. CT vs Renewables) and dispatch (coal vs. gas) can be evaluated. The natural gas prices evaluated in the 2020 IRP are shown in the chart below.

**FIGURE A-2**  
**NATURAL GAS PRICE SENSITIVITIES**



The high and low natural gas price sensitivities were developed using a combination of high and low market and fundamental projections. The high and low market natural gas prices were developed using statistical analysis on market quotes to determine a 10<sup>th</sup> and 90<sup>th</sup> percentile probability. The high and low fundamental natural gas prices were derived using the base fundamental forecast and the EIA's 2020 Annual Energy Outlook (AEO) natural gas price forecasts from its Reference Case, Low Oil and Gas Supply Case, and High Oil and Gas Supply case.

## CAPITAL COST SENSITIVITIES

Three capital cost sensitivities were performed. As discussed in Appendix G, most technologies include technology specific Technology Forecast Factors which were sourced from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2020 which provides costs projections for various

technologies through the planning period as an input to the National Energy Modeling System (NEMS) utilized by the EIA for the AEO. More nascent technologies, such as battery storage and, to a lesser extent, PV solar, have relatively steep projected cost declines over time compared to more established technologies such as CCs and CTs. The first capital cost sensitivity evaluated the impact on the expansion plan of lower and higher reductions in solar PV costs as shown in Table A-6.

**TABLE A-6**

**SOLAR & SOLAR + STORAGE CAPITAL COST SENSITIVITIES – PROJECTED PERCENT COST REDUCTION FROM 2020 TO 2029 BASED ON REAL 2020\$**

	LOW	BASE	HIGH
Solar PV % Reduction in Cost	-54%	-40%	-20%
Solar PV + Storage % Reduction in Cost	-61%	-46%	-26%

The second capital cost sensitivity evaluated the impact of reducing the asset life of a CT or CC from 35 years to 25 years. While the Company believes that natural gas is necessary for transitioning to a net-zero CO<sub>2</sub> emission future, this sensitivity considered the risk of new natural gas assets realizing an earlier than normal retirement.

The final capital cost sensitivity evaluated a reduction in battery storage costs to determine the impact on CT versus battery selection. Currently, the Company assumes that battery storage costs will decline by approximately 45% over the next decade. This sensitivity increases the cost decline to approximately 55%.

**HIGH ENERGY REDUCTION FROM DEP'S DSDR PROGRAM**

While the IRP base planning assumptions include energy reductions for DEP's Distribution System Demand Response Program, additional historical measurement and verification shows potential for further energy reduction from this program. The test year used for the IRP, 2018, provided approximately 100,000 MWhs of energy reduction by 2025, when the program would be fully implemented. Using a test year of 2017, the program could reduce energy by up to 400,000 MWhs, or 0.6% reduction in load for DEP, by the same timeframe. High level estimates suggest that this



additional energy reduction, if realized, could result in approximately 140,000 ton of CO<sub>2</sub> reduction per year. While this additional energy reduction would further lower load on the DEP side, the reduction in load could also impact the energy transfer between utilities as part of the JDA. The additional reduction in energy will not impact the programs peak reduction capacity.

## TECHNOLOGY ADVANCEMENTS

In some instances, certain technologies may not be considered “economic” within the planning horizon. However, these technologies may show significantly more value beyond the planning horizon particularly under strict carbon policies. Additionally, these resources may be required to achieve certain policy goals prior to the end of the planning horizon. For these reasons, the following technologies were evaluated in the 2020 IRP.

- **Small Modular Reactors (SMR)** – In order to achieve climate goals such as 70% CO<sub>2</sub> reduction by 2030 and net-zero carbon reduction by 2050, zero-emitting, load following resources (ZELFR) will be required. DEP evaluated SMRs as an example ZELFR within the planning horizon in several portfolios.
- **Offshore Wind** – While offshore wind was included in the Company’s High Renewable sensitivity, several portfolios significantly increased the penetration of this resource to determine its impact on achieving 70% carbon reduction by 2030. This increase in penetration is reasonable, and is a likely outcome, if offshore wind is developed off the coast of the Carolinas.
- **Pumped Storage Hydro** – As non-dispatchable resources such as solar and wind become prevalent on the system, the need for storage increases to avoid curtailment and optimize utilization of these carbon free resources. As shown in the Company’s Capacity Value of Battery Storage study, the value of short duration storage erodes rapidly as similar storage durations are added. For this reason, pumped hydro storage that can provide 8 or more hours of charging and generating was considered in cases that included renewable energy beyond that found in the base case. Importantly, pumped hydro storage is not well suited for the DEP footprint, however through the Joint Dispatch Agreement there is some transfer of energy between the two utilities that would potentially be impacted by the inclusion of PSH in DEC.

## ENERGY STORAGE

140 MW of 4-hour Lithium ion batteries are included in all portfolios as placeholders for future assets to provide operational experience on the DEP system. These placeholders represent a limited amount of grid connected battery storage projects that have the potential to provide solutions for the transmission and distribution systems with the possibility of simultaneously providing benefits to the generation resource portfolio.

In addition to these placeholders, solar coupled with storage was included in the various renewable cases and was available for selection in the capacity expansion model. Furthermore, as discussed in Chapter 11, the Company studied the impact of replacing CTs with 4-hour battery storage during various points over the planning horizon. Finally, as part of several of the portfolios presented later in this appendix, battery storage was viewed as a key resource in the presence of increasing renewable penetration and the efforts to achieve certain carbon reduction goals, as well as, in cases where new natural gas generation was not an available resource.

## JOINT PLANNING

As required through the Joint Dispatch Agreement, DEP and DEC must plan to meet future capacity needs as individual utilities without the ability to share firm capacity. However, DEP performed a sensitivity assuming joint planning between DEP and DEC to investigate the benefits of shared resources and how new generation could be delayed. The Joint Planning analysis is discussed later in this appendix.

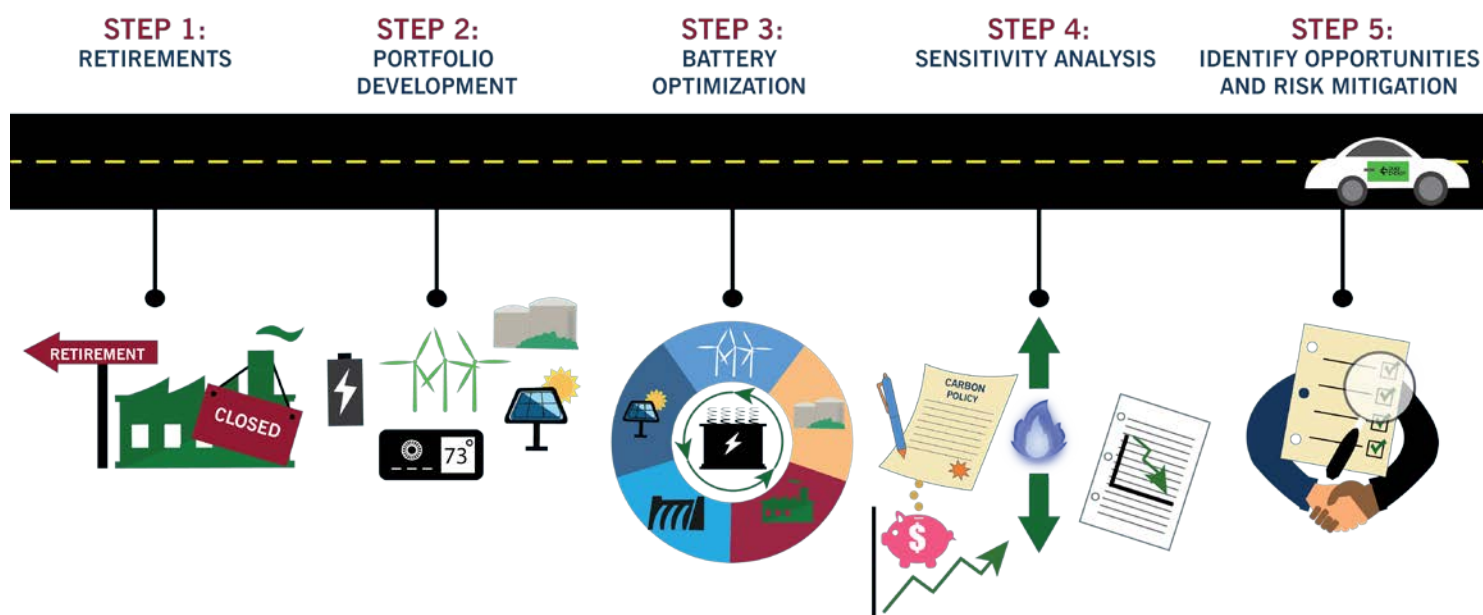
## BASE CASE PORTFOLIO DEVELOPMENT AND RESULTS

The base cases utilize the company's current planning assumptions to determine least cost portfolios in scenarios with and without policy on carbon emissions from the electric generation fleet. These two (2) portfolios include the most economic retirement dates of the company's coal units, as discussed in Chapter 11. These portfolios utilize base planning assumptions for energy efficiency and demand response forecasts to reduce peak demand before incremental resource additions are evaluated. After the base case portfolios have been screened into the portfolio through the capacity expansion model, batteries were evaluated in a production cost model to optimize inclusion in the portfolios. Base Cases were then evaluated in sensitivity analysis to inform development of alternative

portfolios. Below is a simplified process flow diagram for development of the Base Case portfolios.

FIGURE A-3

## SIMPLIFIED PROCESS FLOW DIAGRAM FOR BASE CASE PORTFOLIO DEVELOPMENT AND SENSITIVITY ANALYSIS



### BASE CASE WITHOUT CARBON POLICY

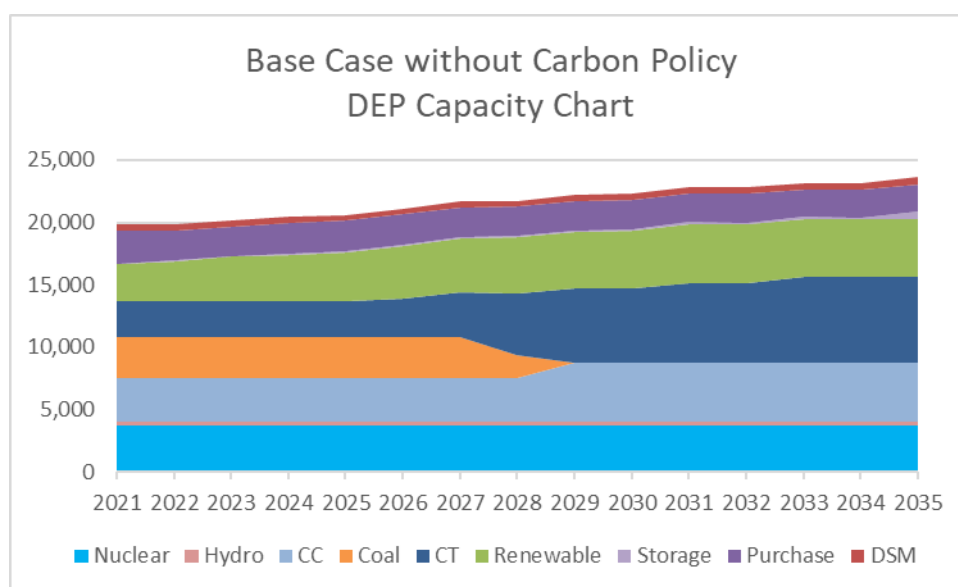
### PORTFOLIO AND RESULTS DISCUSSION

The Base Case without Carbon Policy largely selects new natural gas generation to replace retiring coal generation. This portfolio adds over 5,300 MW of gas capacity to replace the retiring 3,200 MW of coal capacity and meet load growth. Even with the replacement of expiring contracts with like in kind replacement contracts, DEP still has capacity needs in starting in 2026, with the retirement of the Weatherspoon and Blewett CTs, common across all portfolios evaluated. In this scenario without a carbon policy, the additions selected are mainly CTs until the coal units are retired in 2028 and 2029. The system relies on coal generation until it's retired and CTs are added in smaller amounts to avoid excess capacity for a period of time. There are no model selected solar additions in this portfolio, which indicates that above the forecasted solar additions, the system would likely require additional economic support from either a carbon price or other supporting energy policy to continue adding renewable generation to the system. Through the battery optimization in this Base Case, it was found

that a battery would be economic in the place of a CTs built in 2035, in the last year of IRP planning horizon.

**FIGURE A-4**

## DEP CAPACITY CHART - BASE CASE WITHOUT CARBON POLICY



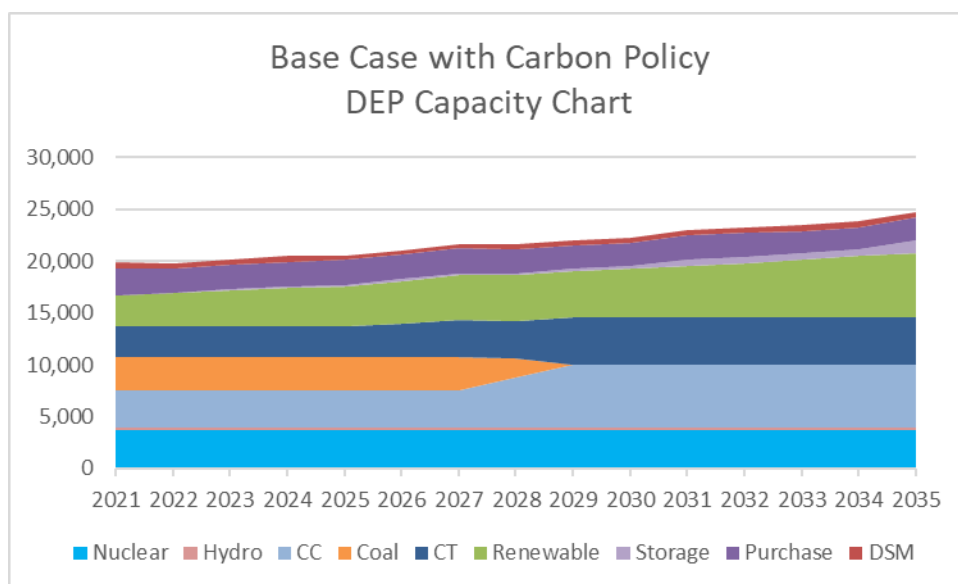
## BASE CASE WITH CARBON POLICY

## PORTFOLIO AND RESULTS DISCUSSION

The Base Case developed under the assumption of future carbon policy results in a more diverse set of resource additions than its no carbon policy counterpart. This case adds 900 MW less of natural gas generation by 2035 compared to the no Carbon Policy case, and instead adds 1,400 MW of additional solar and solar plus storage and 600 MWs of onshore Carolinas wind. This case also found nearly 900 MWs of batteries to be economic starting in 2030 to meet energy and capacity needs created from retiring coal. The addition of the carbon policy drove the model-selected additions of these non-carbon emitting resources in this year's IRP.

FIGURE A-5

# DEP CAPACITY CHART - BASE CASE WITH CARBON POLICY





Below in Table A-7 is a comparison of the Base Case capacity expansion results:

**TABLE A-7**  
**BASE CASE CAPACITY CHANGES WITHIN IRP PLANNING HORIZON**

	BASE CASE WITHOUT CARBON POLICY	BASE CASE WITH CARBON POLICY
PORTFOLIO	A	B
Coal Retirements [MW]	3,208	3,208
Incremental Solar [MW] <sup>†</sup>	2,000	3,425
Incremental Onshore Wind [MW] <sup>†</sup>	0	600
Incremental Offshore Wind [MW]	0	0
Incremental SMR Capacity [MW]	0	0
Incremental Storage [MW] <sup>‡</sup>	698	1,593
Incremental Gas [MW]	5,337	4,276
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW] <sup>*</sup>	825	825

<sup>†</sup>Combined forecasted and model-selected incremental additions by the end of 2035.

<sup>‡</sup>Includes Standalone Storage and Storage at Solar plus Storage sites.

<sup>\*</sup>Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour.

## SENSITIVITY ANALYSIS RESULTS

Following the development of the base planning portfolios, sensitivities were run to inform the development of the alternative portfolios. Table A-8 presents an overview of the year certain resources were selected by the capacity expansion model in each of sensitivities. Red indicates an earlier date than the Base Case with Carbon Policy, green indicates a later date than the Base Case with Carbon Policy, and orange indicates the resource was not selected during the planning horizon.

TABLE A-8  
MATRIX OF FIRST SELECTION OF RESOURCES

	BASE		EE		DSM		LOAD		FUEL PRICE		RENEWABLES		SOLAR COST	
	W/ CO <sub>2</sub> POLICY	W/O CO <sub>2</sub> POLICY	HIGH	LOW	HIGH	LOW	HIGH	LOW	HIGH	LOW	HIGH	LOW	HIGH	LOW
CT	2026	2026	2026	2029	2026	2028	2029	2026	2026	2026	2026	2026	2026	2026
CC	2028	2029	2028	2026	2028	2026	2026	2028	2028	2028	2028	2028	2028	2028
Solar Plus Storage	2030	N/A	2030	2030	2030	2029	2029	2029	2028	2031	2034	2029	N/A	2027
Offshore wind	2033	N/A	2031	2032	2032	2031	2031	2030	2029	2035	2034	2032	2031	2031

Several observations from the sensitivity analysis are discussed below:

- **Timing of new natural gas generation** – The timing of new natural gas generation does not change across sensitivities. In all cases, new gas generation is selected in the 2026 timeframe.
- **Type of new natural gas generation** – CTs are selected as the first natural gas resource in the majority of cases. Only in instances of increased load or those cases with lower penetration of demand side resources are CCs accelerated prior to CTs. The resource mix in DEC also likely plays a role in the resource selection in DEP, and vice versa, as the Joint Dispatch Agreement allows for the transfer of energy between the two utilities. While the capacity expansion model cannot optimize capacity needs between the two utilities, it can optimize energy resources to take advantage of the JDA.
- **Solar Plus Storage** – Solar coupled with storage was selected in 2030 in the Base Case with Carbon Policy. This resource was not selected in the Base Case without a carbon policy, nor was it selected in the high solar cost case. Alternatively, the selection of solar plus storage was accelerated in cases of low DSM and high load. As expected, this resource was delayed when fuel prices were low and solar costs were high, as well as when there were already significant levels of solar on the system already, as was the case in the High Renewable sensitivity.
- **Wind Energy** – Onshore Carolinas Wind was selected in most cases and, was accelerated in many of the sensitivities versus the Base Case with Carbon Policy. Similar to solar plus storage, wind was delayed with high fuel prices and high penetration of solar and wind on the system.

The following tables (Table A-9 and A-10) provide greater detail on the impacts of each sensitivity performed including impact to PVR, CO<sub>2</sub> emissions by 2030 and 2035, and resource selection through 2035.

TABLE A-9

PVRR ANALYSIS OF SENSITIVITIES THROUGH 2050, \$ BILLIONS

	MASS CAP/CAP AND TRADE			CARBON TAX		
Base CO <sub>2</sub>	\$35.7			\$43.7		
	PVRR	DELTA FROM BASE CASE WITH CARBON POLICY	PERCENT CHANGE FROM BASE CASE WITH CARBON POLICY	PVRR	DELTA FROM BASE CASE WITH CARBON POLICY	PERCENT CHANGE FROM BASE CASE WITH CARBON POLICY
Base CO <sub>2</sub> - High Load	\$36.7	\$1.0	2.9%	\$44.5	\$0.8	1.8%
Base CO <sub>2</sub> - Low Load	\$33.6	-\$2.1	-5.8%	\$39.4	-\$4.3	-9.9%
Base CO <sub>2</sub> - High Fuel	\$41.2	\$5.6	15.6%	\$47.8	\$4.1	9.3%
Base CO <sub>2</sub> - Low Fuel	\$33.2	-\$2.5	-6.9%	\$40.9	-\$2.8	-6.3%
Base CO <sub>2</sub> - High Renewables	\$38.2	\$2.5	6.9%	\$45.2	\$1.5	3.5%
Base CO <sub>2</sub> - Low Renewables	\$33.8	-\$1.8	-5.2%	\$42.0	-\$1.7	-3.8%
Base CO <sub>2</sub> - High EE	\$35.1	-\$0.6	-1.6%	\$42.9	-\$0.8	-1.8%
Base CO <sub>2</sub> - Low EE	\$36.2	\$0.6	1.6%	\$44.1	\$0.4	0.8%
Base CO <sub>2</sub> - High DR	\$34.7	-\$1.0	-2.9%	\$42.6	-\$1.1	-2.4%
Base CO <sub>2</sub> - Low DR	\$36.7	\$1.0	2.8%	\$44.3	\$0.6	1.4%
Base CO <sub>2</sub> - High Renew Cost	\$35.9	\$0.2	0.5%	\$43.6	-\$0.1	-0.2%
Base CO <sub>2</sub> - Low Renew Cost	\$35.3	-\$0.3	-1.0%	\$43.2	-\$0.5	-1.2%
Base CO <sub>2</sub> - 25-Year Gas	\$36.3	\$0.6	1.8%	\$44.2	\$0.5	1.2%
Base CO <sub>2</sub> - Pumped Storage	\$36.0	\$0.3	1.0%	\$44.1	\$0.4	0.8%
Base CO <sub>2</sub> - DEP's High Energy DSDR	\$35.7	\$0.0	0.1%	\$43.6	-\$0.1	-0.2%
Min	\$33.2	-\$2.5	-6.9%	\$39.4	-\$4.3	-9.9%
Median	\$35.9	\$0.2	0.5%	\$43.6	-\$0.1	-0.2%
Max	\$41.2	\$5.6	15.6%	\$47.8	\$4.1	9.3%

**TABLE A-10**  
**DEC SENSITIVITY ANALYSIS RESULTS**

	BASE		EE		DSM		Load		Fuel Price		Renewables		Solar Cost	
	w/ CO <sub>2</sub> Policy	w/o CO <sub>2</sub> Policy	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low
CO <sub>2</sub> Reduction by 2030 / 2035	59% / 62%	56% / 53%	60% / 62%	60% / 62%	60% / 62%	59% / 62%	61% / 63%	63% / 70%	60% / 59%	59% / 60%	61% / 66%	60% / 61%	59% / 61%	60% / 63%
2035 Winter Peak Demand	15,966	15,966	15,722	16,027	15,966	15,966	16,086	15,830	15,966	15,966	15,966	15,966	15,966	15,966
EE	243	243	487	182	243	243	243	243	243	243	243	243	243	243
DSM	589	589	589	589	1,011	468	589	589	589	589	589	589	589	589
Generation Added Over Planning Horizon (Nameplate Winter MW) <sup>†</sup>														
Gas Generation	4,276	5,337	3,819	4,276	3,819	4,880	4,276	3,966	3,966	4,423	3,819	4,276	4,423	4,276
Solar <sup>‡</sup>	5,785	4,598	5,785	5,785	5,785	5,873	58,73	5,873	5,873	5,948	6,488	5,018	4,598	6,023
Wind	450	0	750	600	600	750	750	900	1,050	150	300	600	750	750
Storage	1,537	698	1,537	1,537	1,537	1,555	1,555	1,555	1,574	1,499	1,785	1,414	1,237	1,054

<sup>†</sup> MWs represent availability on January 1, 2035.

<sup>‡</sup>Total Solar; Assumes 0.5% annual degradation.



Several key takeaways from the sensitivity analysis include:

- Without a carbon policy, solar and wind resources are not economically selected.
- The incremental 190 Million MWh of EE by 2035, with a coincident peak contribution of 244 MW, in the High EE sensitivity provides \$0.6B to \$0.8B of value versus the base case. While this capacity and energy help avoid a CT over the planning horizon, there is executability risk with achieving these levels of energy efficiency. For this reason, these stretch targets were not included in the Base with and without Carbon Policy cases but were included in the aggressive CO<sub>2</sub> reduction portfolios.
- In cases where incremental capacity is needed, such as the High Load Forecast and Low EE, a CC is accelerated along with solar coupled with storage and wind resources. Notably, these renewable resources are only accelerated into the 2029 and 2030 timeframe. While these resources are projected to have steep cost declines, they are still relatively expensive compared to natural gas generation in the mid-2020 time period.
- While not economic until the 2030 timeframe, onshore Carolinas wind generation shows the greatest gains in penetration in most scenarios.
- As expected, higher fuel prices, lower solar costs, and carbon policy drive increases in solar plus storage resources.
- A review of the sensitivity PVRR analysis highlights that changes in fuel cost had the greatest impact on total PVRR. While the other variables influence incremental energy and resource selections, fuel presents the greatest cost opportunity and risk. The range of uncertainty supports continued diversity in fuel type and regional supply to minimize these risks.

Several other sensitivities investigating the value of Pumped Hydro Storage, a 25-year life for natural gas assets versus the base assumption of a 35-year life, and lower battery storage costs were also developed.

## PUMPED STORAGE HYDRO

As discussed previously, as non-dispatchable renewable resources increase in number in the Carolinas, longer duration energy storage will become critical to maintaining a reliable system. The sensitivity performed in this case was with Base Renewables along with DEP and DEC operating as separate utilities with current transmission capacity between the two utilities which limits the value of additions PSH. A scenario with higher renewable penetration and increased transmission capability between the two utilities would likely increase the value of PSH. The Company believes that under certain climate goals and carbon reduction policies, incremental PSH would be a valuable addition to the fleet.

## 25-YEAR NATURAL GAS ASSETS

Approximately 300 MW of gas generation was replaced with accelerated wind and solar plus storage in the case where the asset life of natural gas CCs and CTs was reduced to 25-years from 35-years. Both wind and solar plus storage generation were accelerated to 2029, which was very similar to the results of the High Fuel scenario shown above.

## BATTERY STORAGE COSTS

In the Base Case with Carbon Policy, battery storage was determined to be economic beginning in the 2030 time period. A CT in 2030 and a CT in 2034 were replaced with 4-hour battery storage. To test the impact of lower battery storage costs, the Company tested the PVRR cost effectiveness of a CT vs 4-hour Li-ion battery storage that was 15% lower cost than the original planning assumption. In DEP, the opportunity to replace a CT with battery storage occurs in 2025, 2028, 2030, and 2034. With these lower costs, the 2028 CT would also be replaced with battery storage. Regardless of this exercise, as noted in Chapter 11 at the time new resources are needed on the DEP system, the Company will solicit bids to fill the resource gap as part of the CPCN process for new generation resources. Only then, will the true costs of competing technologies be fully known.

## 5. DEVELOPMENT OF ALTERNATIVE PORTFOLIO CONFIGURATIONS

While Base Cases with and without Carbon Policy provide insight into the larger theme of the impact of carbon policies to drive reductions from a business as usual case, the company's approach in this

IRP was to analyze multiple pathways that align to the of interest to stakeholders. These portfolios attempt to achieve desired outcomes of ceasing to burn coal in the Company's generation fleet, meeting aggressive carbon reductions goals, and in one scenario transition the fleet without the deployment of new gas generation. The work described in the previous section with respect to sensitivity analysis also helped inform the development of these pathways. While each of these pathways attempts to accomplish its own desired outcomes, the detailed examinations also help quantify tradeoffs of total costs of the implementation and operation of the portfolio, pace of change and impact to the average residential monthly bill, dependency on technological development and deployment, and dependency on policy to enable the transition. This section highlights the additional portfolios analyzed and discusses some of the different requirements for each of the portfolios.

## **ALTERNATIVE PLANNING CASE RESULTS**

### **EARLIEST PRACTICABLE COAL RETIREMENTS**

#### **EARLIEST PRACTICABLE COAL RETIREMENT ANALYSIS**

In the 2020 IRP, the Company evaluated the potential factors that would restrict the Utility from retiring the current coal fleet at their earliest practicable dates. To retire over 3,200 MWs in DEP as earliest as practicable, this analysis suspends traditional "least cost" economic planning considerations, focusing on procurement and construction timelines for replacement capacity. The evaluation of these accelerations is often restricted by infrastructure to enable the replacements. Some of the most impactful factors contributing to earliest practical retirement dates are discussed below:

#### **UTILITY PLANNING RESERVE MARGIN LENGTH**

As with the most economic coal retirement analysis, the earliest practicable coal retirements also considered immediate planning reserve margin length of the utility to retire the capacity without replacement. To the extent possible, units were accelerated based on the available capacity length beyond the minimum planning reserve margin.

## RETIRING COAL SITE TRANSMISSION

After retirements with excess planning capacity, the coal sites were considered for transmission grid impacts. With over 50 years of operations in the Carolinas, some the existing coal sites have become critical for reliability and stability of the grid. Retirements of these stations without replacement onsite often require additional transmission projects which can further lead to delays in retirement of the coal fleet. To the extent possible, replacement generation in the Earliest Practicable case was located at the site of the retiring coal plants to avoid transmission projects which would further delay the retirement of these assets if replacement generation was built offsite.

## INTERCONNECTION TO TRANSMISSION SYSTEM OF REPLACEMENT GENERATION

Also contributing to the ability to accelerate retirement of these assets is the need for infrastructure associated with new replacement generation sites, usually consisting of transmission interconnection, and possible requirements for gas and water infrastructure. The current process for getting through the interconnection queue could be significant given the size of the queue. Once interconnection studies are complete, depending on the outcome of those studies, transmission upgrades to interconnect the replacement capacity may then be required which can add years to the process of replacing existing generation. These timelines were accounted for when considering options for offsite replacement capacity.

## LEVERAGING EXISTING INFRASTRUCTURE

Leveraging existing infrastructure rather than constructing new generation at greenfield sites can enable accelerated retirement of these assets. Siting replacement capacity generation at existing sites can alleviate the need for new land, water sources and reduce transmission upgrades that may be required to maintain grid stability should generation cease to exist at existing coal sites. Where necessary, additional consideration was taken for incremental interstate gas pipeline to provide adequate gas supply to certain transmission advantageous sites.

TABLE A-11

## EARLIEST PRACTICABLE COAL RETIREMENT DATES OF DEP COAL PLANTS

	BASE CASE MOST ECONOMIC RETIREMENT YEAR (JAN 1)	EARLIEST PRACTICABLE COAL RETIREMENT YEAR (JAN 1)	CONSTRAINING FACTOR
Mayo 1	2029	2026	Build-up of transmission-advantageous battery energy storage
Roxboro 1 & 2	2029	2028	Construction of onsite gas capacity
Roxboro 3 & 4	2028	2028	Construction of onsite gas capacity

## FACTORS INFLUENCING EARLIEST PRACTICABLE COAL RETIREMENT DATES

As discussed, the primary consideration in the development of the “earliest practicable” coal retirement dates is the timeline to bring replacement resources into service. Demand-side efforts identified in the IRP help to reduce the amount of resources needed to supply a growing customer base. However, the net demand and energy forecast after all demand-side initiatives is still positive. Hence any retirement of existing capacity resources creates a need for reliable replacement capacity to maintain overall system reliability. With respect to market purchases, it was assumed that in the aggregate expiring purchase contracts of existing traditional fossil resources and renewable energy resources where either extended or replaced in-kind through future RFP activities. This assumption further reduces the need for additional resources that would otherwise be required from the expiry of current purchase power contracts. Additional capacity purchases from neighboring balancing areas was not assumed eligible for replacement capacity in this analysis given the uncertain nature of the availability and cost of such potential purchases as well as the associated transmission requirements to bring in such purchases. More discussion on the ability and costs to increase transfer limits with neighboring service territories is outlined in Chapter 7. Finally, the consideration of earliest practicable coal retirement dates assumes a continued aggressive growth in year-over-year renewable resources as depicted in the Base with Carbon Policy portfolio. After first considering the total impact of demand-side activities, market purchases and renewable additions it was determined that additional reliable capacity would be required in order to enable coal retirements while maintaining adequate planning reserves as discussed in Chapter 9. As a result, to arrive at the earliest practicable coal

retirement dates requires minimizing the time to site, permit, construct and obtain regulatory approval for replacement capacity resources and supporting infrastructure. As previously mentioned, for the “earliest practicable” portfolio this time lag was assumed to be minimized by replacement resources being sited largely at the retiring coal facility locations to leverage existing land, water and transmission infrastructure.

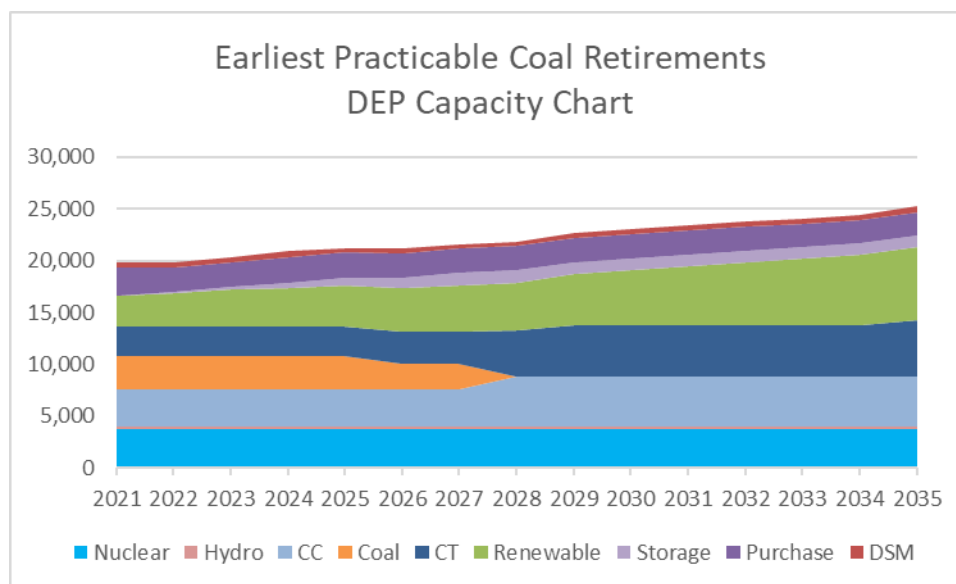
## PORTFOLIO AND RESULTS DISCUSSION

With the earliest practicable retirement dates established, the capacity expansion model was run to optimize the replacement capacity needs while adhering to the prescribed replacements required to enable retirements. This plan utilizes base renewable, energy efficiency and demand response projections, as the high integration rate and high energy efficiency and demand response program penetration may not be practicable. Similar to both Base Case scenarios, the plan adds CT capacity in 2026 to meet the first capacity need in DEP. In the earliest practicable retirement date analysis, it was determined that Mayo could be retired in 2026 with the deployment of utility scale battery storage more quickly than replacing with other traditional on- or offsite capacity. This battery storage build-out from 2023 through 2027 allows for the retirement of the Mayo coal facility, by accelerating battery storage in the early 2030s from the Base Case with Carbon Policy. When all four units at Roxboro Station are retired in 2028, a combined cycle and CTs replace these retiring coal units on-site to avoid the transmission upgrades that would be required if the retiring capacity was replaced offsite. The year 2028 was determined to be the earliest that replacement capacity and transmission projects could be completed in DEP to enable the retirement of the 2,400 MWs at Roxboro Station. Additional build out of battery storage or gas at an offsite location would likely require more time and therefore these retirement dates were selected. This portfolio maintains considerable additions of solar and solar plus storage on par with the Base Case with Carbon Policy, and 750 additional MWs of onshore central Carolinas wind over the Base Case with carbon policy. While the practicality of this plan is challenging, the company believes that with proper policy support to enable this transition, the plan is feasible.



FIGURE A-6

## DEP CAPACITY CHART - EARLIEST PRACTICABLE COAL RETIREMENTS



## 70% CO<sub>2</sub> REDUCTION: HIGH WIND

The 70% CO<sub>2</sub> Reduction: High Wind portfolio outlines a pathway to reduce CO<sub>2</sub> system emissions by 70% by 2030, from a 2005 baseline, by tapping into offshore wind resources off the coast of the Carolinas. This scenario demonstrates the necessary investment requirements and procurement, engineering, and construction challenges to bring this carbon-free resource into the portfolio to reduce the overall emissions of the system. This plan highlights the benefits of bringing these resources into the company's service territory, and illustrates that the retirement of carbon intense resources, such as coal, alone is not enough to reach these lofty goals, but requires access to diverse types of lower and carbon-free energy.

## PORTFOLIO AND RESULTS DISCUSSION

The assumption of earliest practicable retirement dates underlies this plan to enable further reduction in carbon emissions by 2030. This plan also assumes high renewables, energy efficiency, and demand response projections to provide carbon-free capacity and energy to further reduce CO<sub>2</sub> emissions. Critically, the earliest practicable retirement dates, along with high levels of renewable penetration (nearly

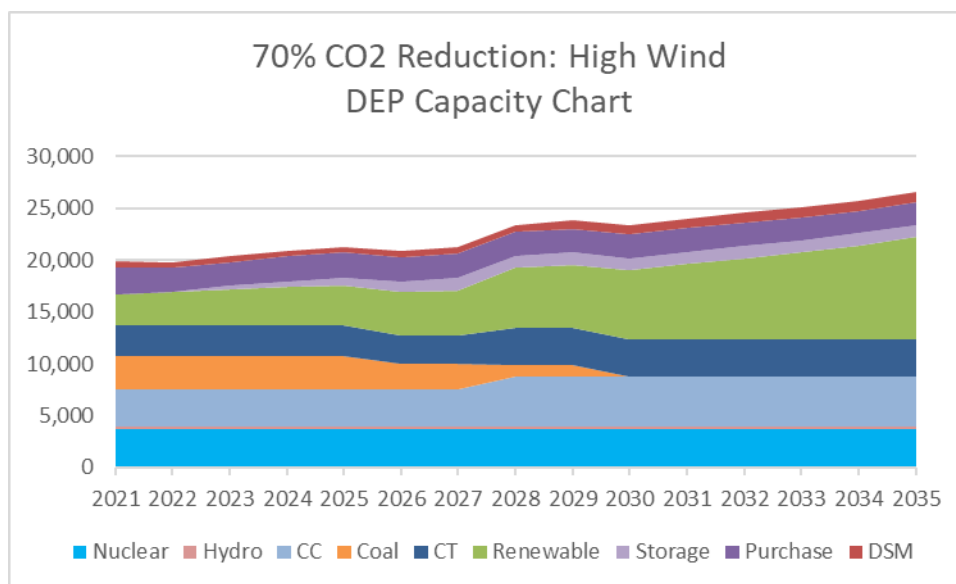
4,000 MWs of solar as a combined system above the Base Case with Carbon Policy, by 2035), is not enough to achieve 70% CO<sub>2</sub> reduction and additional carbon-free resources, such as offshore wind are needed. As with the previous case, gas generation will be required to enable these retirements and provide system flexibility and reliability while further reducing carbon emissions of the system.

This plan assumes 1,200 MWs of offshore wind are incorporated into the DEP service territory by 2030. To maintain enough capacity reserves before the offshore wind can be constructed and connected to the system, Roxboro 1 & 2 retirements are delayed two (2) years from the earliest practicable retirement dates to 2030. Due to the geographical location of the offshore wind resource, significant transmission infrastructure will be required to deliver this energy to the load centers in DEP. While offshore wind can provide bulk carbon free energy, it does not provide one-for-one reliability equivalency. As an intermittent resource, the system will have to respond to variances in output from the offshore wind farm. Additionally, offshore wind is estimated to provide approximately 55% of its nameplate capacity towards meeting DEP's winter peak demand. While offshore wind capacity helps meet DEP's energy needs, the Company still requires traditional gas generation to accelerate coal retirements in this case and provide the needed capacity reserves to fulfill the Company's obligation to serve load.

While this portfolio achieves its intended outcome, it will likely require accelerated technological deployment enhancements and policy support to enable this pathway. While Offshore wind is not necessarily a new technology, deployment in the US at large scale is yet to be demonstrated. The cost of the resource and getting the energy from coastal Carolinas to the load centers in the central part of the states will present implementation challenges. These challenges can be mitigated with effective political and regulatory support and policy.

FIGURE A-7

## DEP CAPACITY CHART - 70% CO<sub>2</sub> REDUCTION: HIGH WIND



## 70% CO<sub>2</sub> REDUCTION: HIGH SMR

The 70% CO<sub>2</sub> Reduction: SMR portfolio outlines a pathway to reduce CO<sub>2</sub> system emissions by 70% by 2030, from a 2005 baseline, by deploying advanced nuclear technologies by the end of this decade. This scenario demonstrates the necessary investment requirements and procurement, engineering, and construction challenges to bring this carbon-free resource into the portfolio to reduce the overall emissions of the system. This plan highlights the benefits of bringing advanced nuclear technologies into the Company's service territory, and illustrates that the retirement of carbon intense resources, such as coal, alone is not enough to reach these lofty goals. As with the 70% CO<sub>2</sub> Reduction: High Wind pathway, 70% CO<sub>2</sub> emissions reduction by 2030 requires access to additional lower carbon and carbon-free energy.

## PORTFOLIO AND RESULTS DISCUSSION

As with the previous 70% CO<sub>2</sub> Reduction case, the assumption of earliest practicable retirement dates underlies this plan, enabling this plan to further reduce carbon emissions by 2030. Similarly, in this case, earliest practicable retirement dates (with the two year delay for Roxboro 1&2 retirement to 2030),

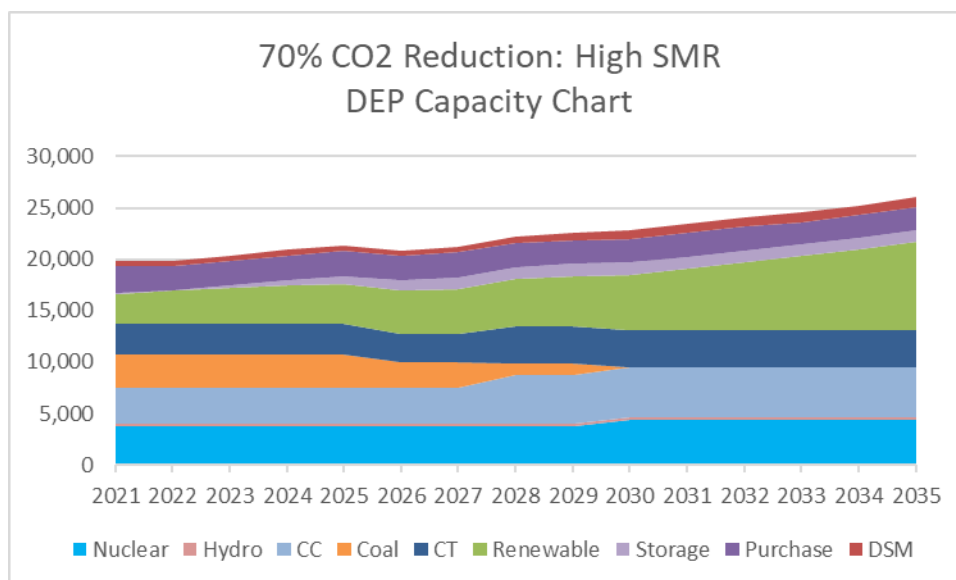
along with high levels of renewable penetration (nearly 4,000 MWs of solar as a combined system above the Base Case with Carbon Policy by 2035), is not enough to achieve the desired carbon reduction goals and additional carbon free resources, such as small modular nuclear reactors (SMRs) are needed. As with the previous cases, gas generation will be required to enable these retirements and provide system flexibility and reliability while further reducing carbon emissions of the system.

This plan assumes the deployment of a 684 MW SMR nuclear plant in DEP by 2030. This technology presents an opportunity for a carbon-free resource that can adjust output up and down to follow trends in load. The addition of SMR capacity in this case is relatively small compared to the DEP system nameplate capacity, but on an energy basis, these dispatchable resources provide a greater density of carbon-free energy as compared to their intermittent renewable counter parts. While the system benefits from these attributes, the ability to license, permit, and construct this emerging technology by 2030 presents a significant challenge. The first full-scale, commercial SMR project is slated for completion at the start of the next decade which is the same time period as the plant in this scenario. To complete a project of this magnitude would require a high level of coordination between state and federal regulators, and even with that assumption, the timeline is still challenged based on the current licensing and construction timeline required to bring this technology to DEP.

While this portfolio achieves its intended outcome, it will require highly effective coordination between the utility, regulatory bodies, and stakeholders to enable this pathway. While nuclear reactors are not a new technology, development and deployment of this new design is yet to be demonstrated at large scale. Uncertainty in the project cost and timeline is another factor that will need to be understood before embarking on a groundbreaking project of this magnitude.

FIGURE A-8

## DEP CAPACITY CHART - 70% CO<sub>2</sub> REDUCTION: HIGH SMR



## NO NEW GAS GENERATION

There is growing interest from environmental advocates and Environmental, Social, and Corporate Governance (ESG) investors to understand the impacts of no longer relying on natural gas as a bridge fuel to a net-zero carbon future. This scenario explores a pathway, given the proper technological and policy advancements, to bridge the gap between now and 2050 without building new gas generation. While gas generation is a mature, economical, and reliable resource, the reliance on natural gas as a bridge fuel has been challenged due to its continued reliance on fossil fuels and risks of stranding these assets. More discussion about the shortening of the book life of new gas assets and utilizing existing gas infrastructure in a net-zero carbon future were discussed earlier in this appendix and in Chapter 16. To evaluate the cost and operability of the system without gas as a transition fuel, this pathway assumes no new gas generation projects and meets the remaining capacity and energy needs of the DEP system with existing and emerging zero-carbon emitting resources, including solar, storage, wind and SMRs.

## PORTFOLIO AND RESULTS DISCUSSION

In a scenario where economical gas generation additions are eliminated, and firm winter capacity remains the binding constraint, the system must rely on the existing portfolio until existing technologies, such as batteries, can be built up on the system and emerging technologies become available, before retiring units in the current fleet. In order to allow technologies to reach maturity and decline in price, the most economic coal retirement dates were used in this scenario. This coal capacity, with a secure fuel source and ability to match generation output with demand, will provide the needed capacity until the nascent technologies needed in the mix can be implemented throughout the systems at scale.

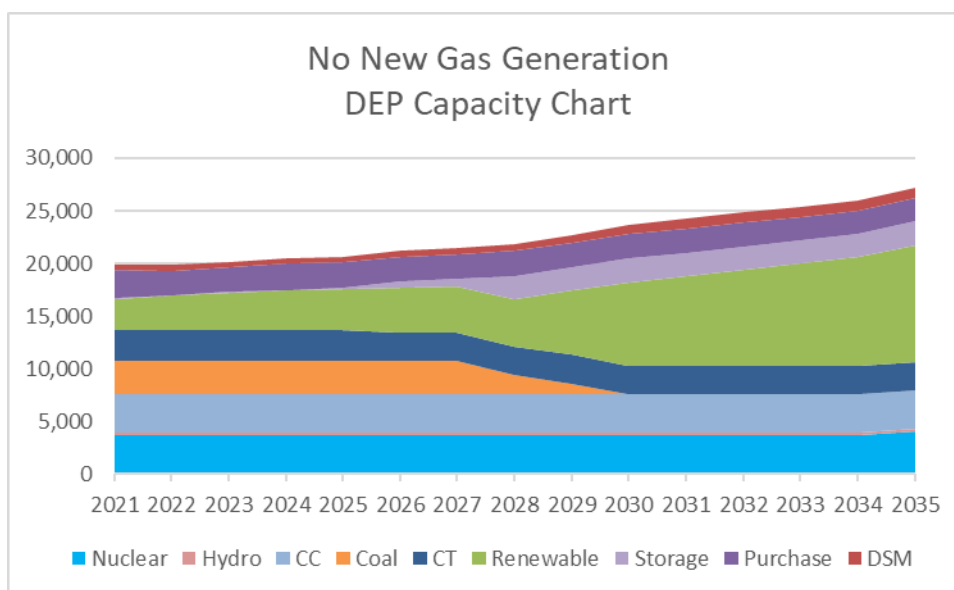
In DEP, even with the slightly later coal retirement dates, the utility must quickly begin procuring replacement resources. This case utilizes a high penetration solar, solar plus storage, and standalone grid tied batteries. By 2030, to ensure the retirement of these units, the utility must add 3,400 MW of 4-hr and 6-hr batteries to the system. Additionally, DEP will need to procure 2,400 MW of offshore wind to help meet energy and capacity needs by 2030. Finally, by the end of the IRP planning horizon, the utility will need to add another 1,000 MW of battery storage and incorporate over 1,700 MW of central Carolinas and high-quality midcontinent wind resources, to keep up with system demand and declining capacity value of battery storage. Without the ability to wait for these technologies to mature, both operationally and economically, DEP is forced to deploy these at large penetrations before they have proven their effectiveness and economic maturity.

Even with high levels of EE and DR, the utility would have to act quickly to develop a system void of new natural gas resources and rely on the current portfolio for longer until these emerging technology resources can be implemented. The challenge does not get easier after the planning window as additional resources begin retiring, which will pose additional new challenges in meeting energy and capacity needs until more zero-emitting, load following resources can be deployed.



FIGURE A-9

## DEP CAPACITY CHART - NO NEW GAS GENERATION



The following Table A-12 is a summary of the system capacity changes in the IRP planning horizon for the Base Cases and Alternative Portfolios. Additionally, Table A-13 provides the assumed retirement date of each DEP coal plant under each portfolio.

TABLE A-12

# BASE CASE AND ALTERNATIVE PORTFOLIO CAPACITY CHANGES WITHIN IRP PLANNING HORIZON

	DUKE ENERGY PROGRESS					
	BASE WITHOUT CARBON POLICY	BASE WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO <sub>2</sub> REDUCTION: HIGH WIND	70% CO <sub>2</sub> REDUCTION: HIGH SMR	NO NEW GAS GENERATION
PORTFOLIO	A	B	C	D	E	F
Coal Retirements [MW]	3,208	3,208	3,208	3,208	3,208	3,208
Incremental Solar [MW] <sup>†</sup>	2,000	3,425	3,500	4,835	4,835	4,985
Incremental Onshore Wind [MW] <sup>†</sup>	0	600	1,350	1,729	1,729	1,729
Incremental Offshore Wind [MW]	0	0	0	1,292	92	2,492
Incremental SMR Capacity [MW]	0	0	0	0	684	0
Incremental Storage [MW] <sup>‡</sup>	698	1,593	1,595	2,010	2,010	5,011
Incremental Gas [MW]	5,337	4,276	3,966	2,138	2,138	0
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW] <sup>*</sup>	832	832	832	1,499	1,499	1,499

<sup>†</sup>Combined forecasted and model-selected incremental additions by the end of 2035

<sup>‡</sup>Includes Standalone Storage and Storage at Solar plus Storage sites

<sup>\*</sup>Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour

TABLE A-13

COAL UNIT RETIREMENTS BY PORTFOLIO

	BASE CASE WITHOUT CARBON POLICY	BASE CASE WITHOUT CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO <sub>2</sub> REDUCTION: HIGH WIND	70% CO <sub>2</sub> REDUCTION: SMR	NO NEW GAS GENERATION
Mayo 1	2029	2029	2026	2026	2026	2029
Roxboro 1 & 2	2029	2029	2028	2030*	2030*	2030**
Roxboro 3 & 4	2028	2028	2028	2028	2028	2028

\*Delayed from Earliest Practicable Coal Retirement Dates for integration of offshore wind/SMR by 2030

\*\*Delayed from Most Economic Coal Retirement Dates for integration of offshore wind by 2030

## 6. PERFORM PORTFOLIO ANALYSIS OVER VARIOUS SCENARIOS

### PORTFOLIO PVRR ANALYSIS

Each of the six pathways identified in the portfolio development analysis were evaluated in more detail with an hourly production cost model (PROSYM) under future fuel price and CO<sub>2</sub> scenarios to determine the robustness of each portfolio under varying fuel and carbon futures. The run matrix for the nine scenarios is illustrated in Table A-14 below.

**TABLE A-14**

### PORTFOLIO ANALYSIS RUN MATRIX

	NO CO <sub>2</sub>	BASE CO <sub>2</sub>	HIGH CO <sub>2</sub>
Low Fuel			
Base Fuel			
High Fuel			

The PROSYM model provided the system production costs for each portfolio under the scenarios illustrated above. The model included DEP's non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with DEC, and as such, the model optimized both DEP and DEC and provided total system (DEP + DEC) production costs. The PROSYM results were separated to reflect system production costs that were solely attributed to DEP to account for the impacts of the JDA. The DEP specific system production costs were then added to the DEP specific capital costs for each portfolio to develop the total PVRR for each portfolio under the given fuel price and CO<sub>2</sub> conditions. The results of this total cost analysis, excluding the explicit cost of the carbon tax to customers (as if the carbon policy were applied as a Cap and Trade program with allowances), is summarized in Table A-15 below.

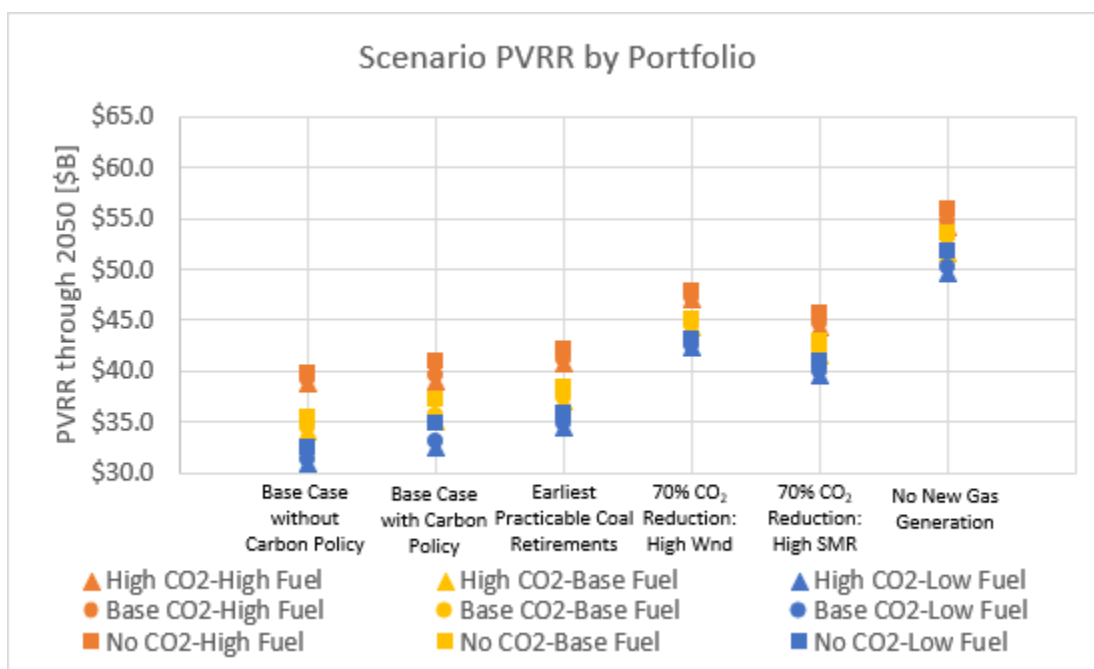
TABLE A-15

## SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, EXCLUDING THE EXPLICIT COST OF CARBON, \$ BILLIONS

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO <sub>2</sub> REDUCTION: HIGH WIND	70% CO <sub>2</sub> REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO <sub>2</sub> -High Fuel	\$38.8	\$39.1	\$40.8	\$47.2	\$44.3	\$54.1
High CO <sub>2</sub> -Base Fuel	\$34.0	\$35.1	\$37.0	\$44.3	\$41.5	\$51.6
High CO <sub>2</sub> -Low Fuel	\$31.0	\$32.5	\$34.5	\$42.4	\$39.6	\$49.7
Base CO <sub>2</sub> -High Fuel	\$39.1	\$39.7	\$41.1	\$47.3	\$44.7	\$54.7
Base CO <sub>2</sub> -Base Fuel	\$34.4	\$35.7	\$37.3	\$44.5	\$41.9	\$52.1
Base CO <sub>2</sub> -Low Fuel	\$31.4	\$33.1	\$34.9	\$42.5	\$39.9	\$50.3
No CO <sub>2</sub> -High Fuel	\$39.9	\$41.0	\$42.1	\$47.9	\$45.7	\$56.0
No CO <sub>2</sub> -Base Fuel	\$35.4	\$37.3	\$38.4	\$45.0	\$42.9	\$53.6
No CO <sub>2</sub> -Low Fuel	\$32.5	\$34.8	\$35.9	\$43.1	\$41.0	\$51.8
Min	\$31.0	\$32.5	\$34.5	\$42.4	\$39.6	\$49.7
Median	\$34.4	\$35.7	\$37.3	\$44.5	\$41.9	\$52.1
Max	\$39.9	\$41.0	\$42.1	\$47.9	\$45.7	\$56.0

FIGURE A-10

# SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, EXCLUDING THE EXPLICIT COST OF CARBON, \$ BILLIONS



As seen in Figure A-10 above, each portfolio, when excluding the cost of carbon, have relatively tightly dispersed total PVRR costs. The plan most affected by the variance in natural gas prices is the Base Case without Carbon Policy, which relies almost exclusively on new gas generation to meet future energy needs. As carbon policy, restrictions on resources, and carbon reduction goals grow, the cost of the plans generally rise, but the dispersion of variance relative to fuel prices shrinks. This is expected, as those plans shift away from natural gas and are naturally less sensitivity to fluctuations in gas price. While the 70% CO<sub>2</sub> reduction and No New Gas Generation cases are less sensitive to gas prices, they are overall more expensive plans, as a result of the costs to add more expensive resources with lower Effective Load Carrying Capabilities (ELCC) and energy output as well as the transmission needed to enable these resources. Shown summarized in Table A-16 below are the results of the same total cost analysis as above, but now including the explicit cost of the carbon tax to customers (as if the carbon policy were applied as tax on carbon emission).

TABLE A-16

SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, INCLUDING  
THE EXPLICIT COST OF CARBON, \$ BILLIONS

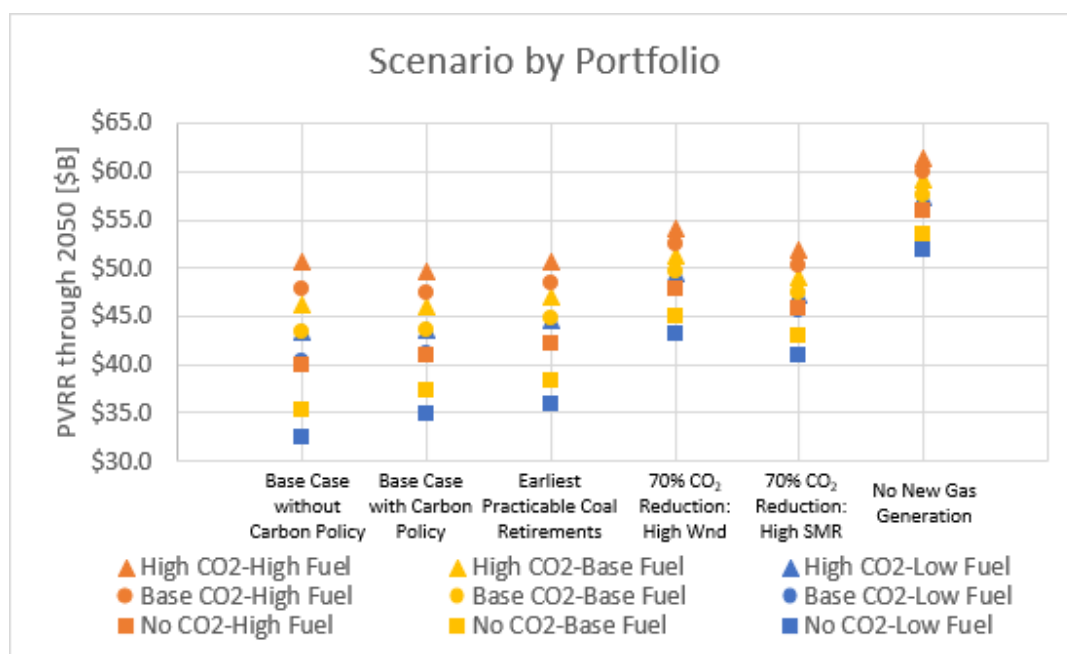
	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO <sub>2</sub> REDUCTION: HIGH WIND	70% CO <sub>2</sub> REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO <sub>2</sub> -High Fuel	\$50.6	\$49.7	\$50.7	\$54.2	\$51.9	\$61.3
High CO <sub>2</sub> -Base Fuel	\$46.2	\$46.0	\$47.0	\$51.4	\$49.1	\$59.1
High CO <sub>2</sub> -Low Fuel	\$43.3	\$43.5	\$44.6	\$49.5	\$47.2	\$57.3
Base CO <sub>2</sub> -High Fuel	\$47.8	\$47.4	\$48.4	\$52.5	\$50.3	\$59.9
Base CO <sub>2</sub> -Base Fuel	\$43.3	\$43.7	\$44.7	\$49.7	\$47.5	\$57.6
Base CO <sub>2</sub> -Low Fuel	\$40.5	\$41.2	\$42.3	\$47.8	\$45.6	\$55.9
No CO <sub>2</sub> -High Fuel	\$39.9	\$41.0	\$42.1	\$47.9	\$45.7	\$56.0
No CO <sub>2</sub> -Base Fuel	\$35.4	\$37.3	\$38.4	\$45.0	\$42.9	\$53.6
No CO <sub>2</sub> -Low Fuel	\$32.5	\$34.8	\$35.9	\$43.1	\$41.0	\$51.8

Min	\$32.5	\$34.8	\$35.9	\$43.1	\$41.0	\$51.8
Median	\$43.3	\$43.5	\$44.6	\$49.5	\$47.2	\$57.3
Max	\$50.6	\$49.7	\$50.7	\$54.2	\$51.9	\$61.3



FIGURE A-11

## SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, INCLUDING THE EXPLICIT COST OF CARBON, \$ BILLIONS



In contrast to the previous view, when the costs of carbon are included in the total cost of the plan, the range of PVRRs for each plan is increased. It can be seen that the Base Case without Carbon Policy is again the portfolio that is most sensitive to fuel and carbon policies. While the lowest cost for the Base Case with Carbon Policy and Earliest Practicable Retirements is higher than Base Case without Carbon Policy, the cost ceiling is lower, due to less natural gas on the system, with its associated carbon emissions and cost based on the price of natural gas. Again, the highest reduction plans, the 70% CO<sub>2</sub> Reduction plans and the No New Gas Generation Plan are less sensitive to the fuel and carbon variables, but are overall more expensive plans, though the gap is smaller when the cost of carbon is considered. The results of these PVRRs are dependent on the structural and policy changes that enable carbon reductions, which will be discussed later in this appendix.

## AVERAGE RESIDENTIAL MONTHLY BILL IMPACT

The total present value revenue requirement (PVRR) of a plan is a common and useful financial metric in Integrated Resource Planning to measure the cost of the plan over a long period of time. This metric will capture the costs and benefit of accelerating retirements, building new generation and associated transmission, and changing fuel prices and operation costs over time. While this is an important metric, the company is also concerned about the cost to customers on an immediate basis, as providing affordable energy is critical to the company's mission. The analysis of estimating the average residential monthly bill impact attempts to quantify how much a residential customer, using 1,000 kWh of energy a month, can expect to see their bill increase over 2020 costs of service due to the changes identified in this IRP. Table A-17 that shows the resulting increase to a residential customers bill for each of the plans through 2030 and 2035 and the average annual percentage change from 2020 through 2030 and 2035, in the company's base gas price and base carbon price scenario, while excluding the explicit cost of the carbon tax to customer.

**TABLE A-17**

### SCENARIO ANALYSIS AVERAGE MONTHLY RESIDENTIAL BILL IMPACT FOR A HOUSEHOLD USING 1000 KWH

	2030		2035	
	AVERAGE RESIDENTIAL MONTHLY BILL IMPACT	AVERAGE ANNUAL PERCENTAGE CHANGE IN RESIDENTIAL BILLS	AVERAGE RESIDENTIAL MONTHLY BILL IMPACT	AVERAGE ANNUAL PERCENTAGE CHANGE IN RESIDENTIAL BILLS
Base Case without Carbon Policy	\$13	1.2%	\$21	1.2%
Base Case with Carbon Policy	\$15	1.3%	\$27	1.5%
Earliest Practicable Coal Retirements	\$16	1.4%	\$24	1.4%
70% CO <sub>2</sub> Reductions: High Wind	\$31	2.7%	\$39	2.1%
70% CO <sub>2</sub> Reductions: High SMR	\$27	2.4%	\$36	1.9%
No New Gas Generation	\$49	4.0%	\$58	2.9%

Table A-17 shows that the plans with earlier transitions to lower carbon future portfolios and more

expensive technologies will see greater cost increase to their bills earlier, while the plans that wait longer to transition, and allow for emerging technologies to decrease in price, may lessen and defer some of those costs increases. With projected declining cost curves for emerging carbon free resources the pace of adoption plays a critical role in the ultimate cost to consumers.

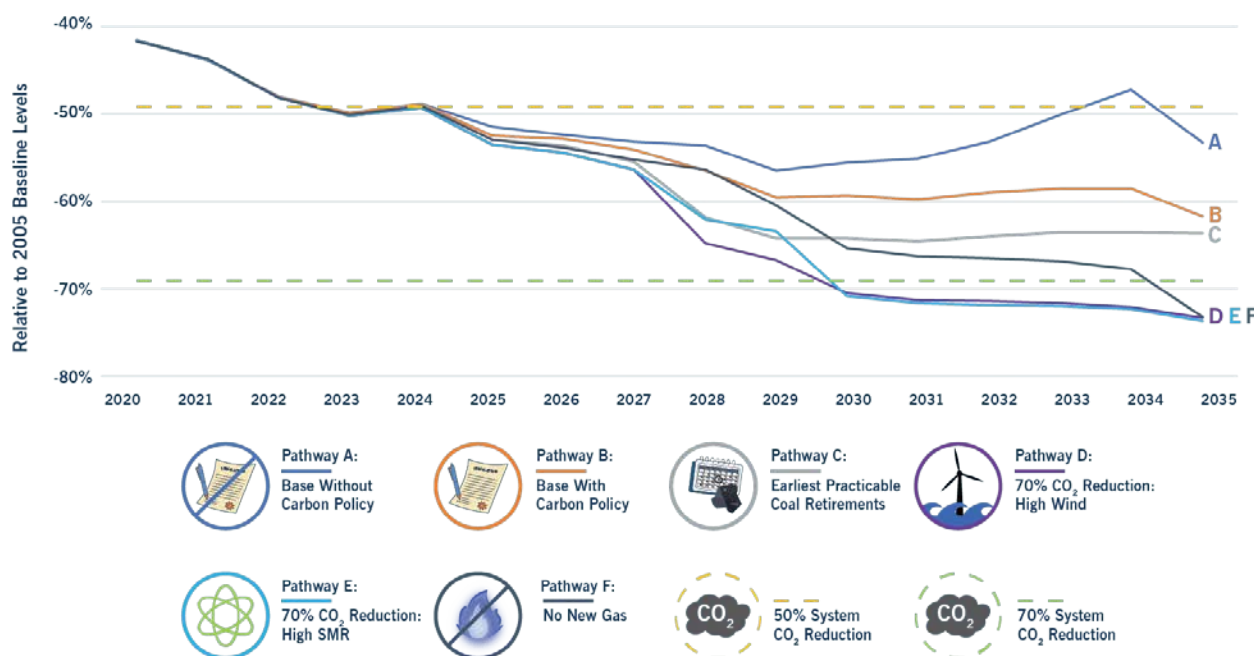
It should be noted that integrating large scale regional energy infrastructure projects, such as bringing offshore wind energy into the Carolinas, would likely require statewide policies. It is likely that the resource and the transmission infrastructure costs to move the energy from the coast to load centers could be spread across all customers in the state rather than those of a single utility. Notwithstanding this possibility, for the purposes of developing No New Gas Portfolio all energy, capacity and associated costs for the results shown are for DEP only, with the recognition that future energy policy could more evenly spread costs across utilities.

## PORTFOLIO CARBON REDUCTIONS ANALYSIS

While cost is undoubtedly an important factor, one of the most crucial aspects analyzed in this IRP is the trade-off between costs and carbon reductions. The graph below charts the carbon reductions for the combined DEP/DEC system of each of the portfolios in the base fuel and base carbon scenario through the IRP planning window. The resources added throughout time, price on carbon emissions (or lack thereof), and relative price between carbon intense fuels influence these carbon emissions. Additional discussion is presented below

FIGURE A-12

## COMBINED DEP/DEC CARBON REDUCTION BY PORTFOLIO IN BASE FUEL AND BASE CARBON SCENARIO



Through 2024 there are no notable changes in carbon emission reductions between the portfolios. Base Planning without Carbon Policy (Pathway A) continues a trajectory of lowering carbon emissions through 2029, albeit at a slower pace than other pathways, as low cost, lower carbon intense natural gas and increasing penetration of solar offsets higher carbon intense coal generation. As gas price begins to rise in the transition from market fuel prices to fundamental fuel prices, less expensive coal generation becomes more prevalent when a carbon tax is not present. Upon retirement, and replacement of Marshall station in 2035, and replacement with gas generation, pathway A sees a reduction in carbon emission again at the end of the planning horizon.

In 2025 the carbon tax comes into effect in pathways B through F, driving the emissions from carbon intense resources down. Increasing additions of solar generation along with the economic pressure of the price on carbon continues to drive down carbon reductions in the Base Planning with Carbon Policy (Pathway B). Growing load and rising gas prices minimize the reductions realized by renewables additions in the 2030, resulting in flat CO<sub>2</sub> reduction until 2035, when Marshall is retired.

As coal and other traditional generation retirements take place throughout the mid-2020s, the carbon reductions between the pathways begin to diverge, resulting in a range of carbon reduction of 56% to 71% from 2005 baseline. Pathways D and E continue to rise to 70% with the retirement of Belews Creek and Marshall Stations in these scenarios by 2030, where Pathways F flattens out from 2029 through 2035, when Marshall retires in this case. By 2035, Pathways D, E, and F converge again around 73%, when the resource types in these portfolios converge at the end of the IRP horizon with similar penetrations of non-carbon emitting resources.

**TABLE A-18**

**SCENARIO REDUCTIONS IN 2030 FOR EACH PORTFOLIO**

	BASE CASE WITHOUT CARBON POLICY	BASE CASE WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO <sub>2</sub> REDUCTION: HIGH WIND	70% CO <sub>2</sub> REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO <sub>2</sub> -High Fuel	55.9%	58.7%	64.3%	70.5%	70.9%	64.9%
High CO <sub>2</sub> -Base Fuel	56.6%	59.4%	64.3%	70.5%	70.8%	65.5%
High CO <sub>2</sub> -Low Fuel	56.7%	59.5%	64.2%	70.5%	70.8%	65.6%
Base CO <sub>2</sub> -High Fuel	55.7%	58.5%	64.3%	70.5%	70.8%	64.7%
Base CO <sub>2</sub> -Base Fuel	56.4%	59.3%	64.2%	70.5%	70.8%	65.4%
Base CO <sub>2</sub> -Low Fuel	56.7%	59.5%	64.2%	70.5%	70.8%	65.5%
No CO <sub>2</sub> -High Fuel	53.4%	56.5%	64.2%	70.4%	70.8%	63.6%
No CO <sub>2</sub> -Base Fuel	55.5%	58.4%	64.1%	70.4%	70.7%	64.6%
No CO <sub>2</sub> -Low Fuel	56.0%	58.9%	63.9%	70.2%	70.4%	65.1%
Reduction Range	3.4%	3.0%	0.4%	0.3%	0.5%	2.0%

**TABLE A-19**  
**SCENARIO REDUCTIONS IN 2035 FOR EACH PORTFOLIO**

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO <sub>2</sub> REDUCTION: HIGH WIND	70% CO <sub>2</sub> REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO <sub>2</sub> -High Fuel	56.3%	61.1%	63.6%	73.3%	73.7%	72.6%
High CO <sub>2</sub> -Base Fuel	57.2%	61.9%	63.6%	73.3%	73.6%	73.3%
High CO <sub>2</sub> -Low Fuel	57.3%	62.0%	63.6%	73.3%	73.6%	73.5%
Base CO <sub>2</sub> -High Fuel	54.3%	59.3%	63.6%	73.3%	73.6%	72.1%
Base CO <sub>2</sub> -Base Fuel	57.0%	61.7%	63.6%	73.3%	73.6%	73.2%
Base CO <sub>2</sub> Low Fuel	57.2%	61.9%	63.6%	73.3%	73.6%	73.5%
No CO <sub>2</sub> -High Fuel	49.4%	54.9%	63.6%	73.3%	73.6%	68.1%
No CO <sub>2</sub> -Base Fuel	53.2%	58.3%	63.6%	73.3%	73.6%	71.1%
No CO <sub>2</sub> -Low Fuel	55.5%	60.4%	63.5%	73.2%	73.5%	72.6%
Reduction Range	7.9%	7.1%	0.2%	0.1%	0.1%	5.4%

Through 2030, the plans with the most sensitivity in carbon emissions are the Base Cases, again due to their continued operations of Coal through the most economic retirement dates, and the additions of natural gas generation throughout the planning horizon. The CO<sub>2</sub> reduction range for the remaining four portfolios is relatively tight, within a 0.5% or less variance for the plans the utilize the earliest practicable retirement dates, and 2% for No New Gas Generation, which does not deploy new natural gas, but relies on the most economic retirement dates of the coal units for deployment of other existing and emerging technologies to replace the retiring capacity.

These observations though 2030 are amplified by 2035. The cases with the most economic coal retirement dates see ranges of carbon reductions from 7.9% in the Base Case without Carbon Policy to 5.4% in the No New Gas Generation plan. Conversely, the plans with the higher costs also deliver consistency in carbon reductions, with emission varying very little with changes to carbon and fuel pricing.

## IDENTIFYING OPPORTUNITIES AND RISK MITIGATION

While each of these plans comes with inherent risks, such as exposure to fuel and carbon pricing or early adoption of emerging technologies with cost and operational uncertainties, the utility will have to continue to have constructive conversations with stakeholders, regulators, and customers to identify and mitigate risks that would prevent the company from providing clean, affordable, and reliable energy. Below discusses some of these risks and mitigating measure:

- **Earliest Practicable Coal Retirements** – While the PVRR and Average Residential Monthly Bill Impact results for Earliest Practicable Coal Retirements are relatively comparable to the Base Case with Carbon Policy, this portfolio does present additional potential tradeoffs and dependency on a number of factors. The regulatory approval and feasibility of procuring the replacement generation are foremost on this list. Additionally, some of the earliest practicable coal retirement are predicated on replacement onsite, leveraging existing infrastructure. This assumption avoids transmission upgrades at some of the retiring coal sites to reduce replacement timelines, and results in lower costs of the plan. The most economic retirement dates of the coal units do not assumed replacement at site, and do not benefit from this cost saving. This provides optionality in the replacement process for the cheapest alternatives to be selected but does incur more cost to the plan for the associated transmission upgrades. Project cost risks associated with these accelerated retirements may put stresses on supply chain driving price variations. Furthermore, deploying economically maturing technologies, like batteries, at large scale may increase cost and operational risk, while opting for earlier retirement of coal units by relying on natural gas may impact of deploying lower carbon and ZEFLR technologies in the future or the associated customer impact to do so.
- **Solar Interconnection** – While solar and other intermittent technologies may help lower exposure to variability in the price of fuels and can help reduce carbon emissions, the interconnection and operation of these resources will have to continue to be studied and advanced to allow for affordable and reliable operation of the system.
- **Onshore Wind Integration** – Several studies throughout the industry identify the value of combining variable energy resources like solar and wind with different but potentially complimentary production profiles. Integration of these resources can help continue to lower carbon emissions and spur economic development in the region, but overcoming the historic



challenges to siting onshore wind in the Carolinas is an issue that requires further study.

- **Offshore Wind Integration** – A largely untapped resource sits just a few miles off the coast of the Carolinas. While there are several hurdles to incorporating this new generation source in the Carolinas systems, such as construction of these wind resources, transmitting that energy to land and then delivering it to the Company's load centers, there is a great opportunity to further reduce carbon emissions and add bulk amounts of zero fuel cost generation to the fleet.
- **ZELFR Development** – While emerging technologies, such as SMRs, were deployed in this IRP, the general development of zero-emitting, load following resources across a range of options will be important to de-risking the transition to a net-zero carbon future.
- **System Operability** – The system operators will have to continue to learn and adapt to new, intermittent and variable energy resources on the system to balance load and generation, utilizing and advancing the flexibility of the existing fleet, while leveraging resources like energy storage and demand side management to continue to provide safe and reliable energy. These transformations envisioned will also rely on significant advancements in the sophistication of the grid control systems needed to manage system operations with these more diverse and distributed new energy resources.

## OTHER FINDINGS AND INSIGHTS

- **Gas as a transition fuel** - The No New Gas Generation portfolio in this IRP demonstrates that natural gas remains a cost-effective way to accelerate the remaining coal retirements over the term of this IRP. Many independent studies and articles have supported the continued role of natural gas to balance the intermittency of renewables and continue to decarbonize the system. As shown in the emissions trajectories graph, the No New Gas portfolio emits more CO<sub>2</sub>, over the fifteen-year period through 2035 and is significantly more costly than the 70% Carbon Reduction by 2030 portfolios (D and E) that include natural gas as a replacement resource. Eliminating natural gas generation as an option is likely to have the unintended effect of delaying coal retirements and increasing CO<sub>2</sub> in the interim, as more coal generation is required to serve load without new efficient natural gas resources as a transition technology.

- Gas transportation services** - On July 5th, 2020 Dominion Energy and Duke Energy announced the cancellation of Atlantic Coast Pipeline (ACP) citing anticipated delays and increasing cost uncertainty due to on-going permitting and legal challenges. DEP and DEC still need additional firm interstate transportation service to support existing and future gas generation in the Carolinas despite the cancellation of the project. The 2020 IRP assumes incremental firm transportation service volumes as contemplated in the ACP project are needed from alternate pipeline providers to cost effectively support both existing natural gas generation fleet and future combined cycle natural gas generation growth. Additionally, incremental firm interstate transportation service is assumed to be procured for any new combined cycle natural gas resource selected in the generation portfolios in this IRP along with firm transportation service cost estimates. The estimated firm transportation service costs were considered in the resource selection process and are included in the financial results presented. Consistent with past IRPs, the planning process does not assume incremental interstate capacity is procured for additional simple cycle CTs given their low capacity factors. Rather, CTs are planned as dual fuel units that are ultimately connected to Transco Zone 5 and will rely on delivered Zone 5 gas supply or if needed ultra-low sulfur fuel oil during winter periods where natural gas has limited availability, the pipeline has additional constraints, or gas is higher priced than the cost to operate on fuel oil. Additional discussion on ACP and Fuel Supply can be found in Appendix F.
- Discussion on Levelized Cost of Energy (LCOE)** - A common source of confusion over the economics of replacement generation for coal retirements are “Levelized Cost of Energy” reports that attempt to compare all-in costs divided by total energy production on a \$/MWh basis. While this can be a useful high-level economic screening tool, it does not speak to the capacity value of a resource, nor does it recognize time value differences in energy production, which can vary dramatically as is the case with high levels of renewable resources. Simple LCOE analysis ignores the reality that it can take several times the amount of installed capacity of certain intermittent resources to produce the same reliability of dispatchable resources, even if those resources are paired with energy storage. This multiplier effect can create additional hurdles related to the permitting and interconnection of a significantly larger amount of resources (on a nameplate MW basis), which naturally has cost implications. To illustrate the multiplier effect, the Company has developed a Portfolio Screening Tool which will be released to the public shortly after the IRP filing.
- Emerging Technologies Decommissioning Costs** – Industry research is beginning to address decommissioning challenges in cost and potential materials recycling opportunities for these

new and emerging technologies. While there are allowances for some costs at end of life, more information will be needed to forecast these costs and the resource selections are being made.

- **A balanced approach to aggressive carbon reduction goals** – The company has stated that a balanced portfolio of resources with varying attributes to produce carbon-free energy, respond to variations in load and generation, shift energy, and reduce overall energy and demand is an important aspect for the Company to consider in resource planning. A combination and blend of these resources in the portfolio may help reduce reliance on the development or price declines of a single resource type and provide the system with the balance of attributes to reliably and more affordably meet the customers' energy needs.

## VALUE OF JOINT PLANNING

To demonstrate the value of sharing capacity with DEC, a Joint Planning Case was developed to examine the impact of joint capacity planning on the resource plans. The impacts were determined by comparing how the combined Base Case with Carbon Policy plans for DEP and DEC would change if a 17% minimum winter planning reserve margin was applied at the combined system level, rather than the individual company level.

An evaluation was performed comparing the Base Case with Carbon Policy plans for DEP and DEC to a combined Joint Planning Case in which existing and future capacity resources could be shared between DEP and DEC to meet the 17% minimum winter planning reserve margin. Table A-20 shows the base expansion plans (Base Case with Carbon Policy for both DEP and DEC) through 2035, if separately planned, compared to the Joint Planning Case. The sum of the two combined resource requirements is then compared to the amount of resources needed if DEP and DEC could jointly plan for capacity. Planned projects and the economic selection of renewables and batteries were not reoptimized for this sensitivity. Delaying and accelerating of gas units was used to preserve the joint system's 17% reserve margin. Years where the Joint Planning Case differ from the individual Utility cases are highlighted.

TABLE A-20

COMPARISON OF BASE CASE WITH CARBON POLICY OF INDIVIDUAL UTILITY PLANNING TO JOINT PLANNING SENSITIVITY

	INDIVIDUAL UTILITY PLANNING							JOINT PLANNING	
	DEP		DEC		COMBINED SYSTEM			COMBINED SYSTEM	
	CC	CT	CC	CT	CC	CT		CC	CT
2021	0	0	0	0	0	0	2021	0	0
2022	0	0	0	0	0	0	2022	0	0
2023	0	0	0	0	0	0	2023	0	0
2024	0	0	0	0	0	0	2024	0	0
2025	0	0	0	0	0	0	2025	0	0
2026	0	457	0	0	0	457	2026	0	457
2027	0	914	0	0	0	914	2027	0	457
2028	1,224	914	0	0	1,224	914	2028	1,224	914
2029	2,448	1,828	0	0	2,448	1,828	2029	2,448	1,828
2030	2,448	1,828	0	457	2,448	2,285	2030	2,448	1,828
2031	2,448	1,828	0	914	2,448	2,742	2031	2,448	2,285
2032	2,448	1,828	0	914	2,448	2,742	2032	2,448	2,285
2033	2,448	1,828	0	914	2,448	2,742	2033	2,448	2,742
2034	2,448	1,828	0	914	2,448	2,742	2034	2,448	2,742
2035	2,448	1,828	1,224	1,828	3,672	3,656	2035	3,672	3,199

A comparison of the DEP and DEC Combined Base Case resource requirements to the Joint Planning Scenario requirements illustrates the ability to defer a CT resource starting in 2027. Consequently, the Joint Planning Case also results in a lower overall reserve margin. This is confirmed by a review of the reserve margins for the Combined Base Case as compared to the Joint Planning Case, which averaged 18.3% and 18.2%, respectively, from the first need in DEP in 2026 over the remaining IRP planning horizon. The ability to share resources and achieve incrementally lower reserve margins from year to year in the Joint Planning Case illustrates the efficiency and economic potential for DEP and DEC when planning for capacity jointly. Finally, as discussed in the Company's updated Resource Adequacy Study the benefits of a joint system can have beneficial results and could potentially lead to even a slightly lower reserve margin than the 17% examined in the Joint Planning Case.





**B**

**DUKE ENERGY  
PROGRESS OWNED  
GENERATION**

Corrected 11.06.2020

## APPENDIX B: DUKE ENERGY PROGRESS OWNED GENERATION

Duke Energy Progress' generation portfolio includes a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve its customers. Duke Energy Progress-owned generation, as well as purchased power, is evaluated on a real-time basis to select and dispatch the lowest-cost resources to meet system load requirements.

The tables below list the Duke Energy Progress' plants in service in North Carolina (NC) and South Carolina (SC) with plant statistics, and the system's total generating capability.

# EXISTING GENERATING UNITS AND RATINGS A, B, C, D, E

ALL GENERATING UNIT RATINGS ARE AS OF JANUARY 1, 2020 UNLESS OTHERWISE NOTED

COAL									
PLANT	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Mayo <sup>2</sup>	1	746	727	Roxboro, NC	Coal	Intermediate	36	9	N/A
Roxboro	1	380	379	Semora, NC	Coal	Intermediate	53	9	N/A
Roxboro	2	673	668	Semora, NC	Coal	Intermediate	51	9	N/A
Roxboro <sup>2</sup>	3	698	694	Semora, NC	Coal	Intermediate	46	8	N/A
Roxboro <sup>2</sup>	4	711	698	Semora, NC	Coal	Intermediate	39	8	N/A
Total Coal		3,208	3,166						



# COMBUSTION TURBINES

	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Asheville	3	185	160	Arden, NC	Natural Gas/Oil	Peaking	20	20	N/A
Asheville	4	185	160	Arden, NC	Natural Gas/Oil	Peaking	19	20	N/A
Blewett	1	17	13	Lilesville, NC	Oil	Peaking	48	6	N/A
Blewett	2	17	13	Lilesville, NC	Oil	Peaking	48	6	N/A
Blewett	3	17	13	Lilesville, NC	Oil	Peaking	48	6	N/A
Blewett	4	17	13	Lilesville, NC	Oil	Peaking	48	6	N/A
Darlington	1	63	50	Hartsville, S.C.	Natural Gas/Oil	Peaking	45	3 months	N/A
Darlington	2	64	48	Hartsville, S.C.	Oil	Peaking	45	3 months	N/A
Darlington	3	63	50	Hartsville, S.C.	Natural Gas/Oil	Peaking	45	3 months	N/A
Darlington	4	66	48	Hartsville, S.C.	Oil	Peaking	45	3 months	N/A
Darlington	6	62	43	Hartsville, S.C.	Oil	Peaking	45	3 months	N/A
Darlington	7	65	47	Hartsville, S.C.	Natural Gas/Oil	Peaking	45	3 months	N/A
Darlington	8	66	44	Hartsville, S.C.	Oil	Peaking	45	3 months	N/A
Darlington	10	65	49	Hartsville, S.C.	Oil	Peaking	45	3 months	N/A
Darlington	12	133	118	Hartsville, SC	Natural Gas/Oil	Peaking	22	18	N/A
Darlington	13	133	116	Hartsville, SC	Natural Gas/Oil	Peaking	22	18	N/A
Smith <sup>4</sup>	1	197	157	Hamlet, NC	Natural Gas/Oil	Peaking	18	22	N/A
Smith <sup>4</sup>	2	197	156	Hamlet, NC	Natural Gas/Oil	Peaking	18	22	N/A
Smith <sup>4</sup>	3	197	155	Hamlet, NC	Natural Gas/Oil	Peaking	18	22	N/A

COMBUSTION TURBINES (CONT.)									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Smith <sup>4</sup>	4	197	159	Hamlet, NC	Natural Gas/Oil	Peaking	18	22	N/A
Smith <sup>4</sup>	6	197	145	Hamlet, NC	Natural Gas/Oil	Peaking	17	22	N/A
Sutton	4	49	39	Wilmington, NC	Natural Gas/Oil	Peaking	2	34	N/A
Sutton	5	49	39	Wilmington, NC	Natural Gas/Oil	Peaking	2	34	N/A
Wayne	1/10	192	177	Goldsboro, NC	Oil/Natural Gas	Peaking	19	21	N/A
Wayne	2/11	192	174	Goldsboro, NC	Oil/Natural Gas	Peaking	19	21	N/A
Wayne	3/12	197	173	Goldsboro, NC	Oil/Natural Gas	Peaking	19	21	N/A
Wayne	4/13	197	170	Goldsboro, NC	Oil/Natural Gas	Peaking	19	21	N/A
Wayne	5/14	197	163	Goldsboro, NC	Oil/Natural Gas	Peaking	19	30	N/A
Weatherspoon	1	41	31	Lumberton, NC	Natural Gas/Oil	Peaking	49	6	N/A
Weatherspoon	2	41	31	Lumberton, NC	Natural Gas/Oil	Peaking	49	6	N/A
Weatherspoon	3	41	32	Lumberton, NC	Natural Gas/Oil	Peaking	48	6	N/A
Weatherspoon	4	<u>41</u>	<u>30</u>	Lumberton, NC	Natural Gas/Oil	Peaking	48	6	N/A

COMBUSTION TURBINES (CONT.)									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Total NC		2,660	2,203						
Total SC		<u>780</u>	<u>613</u>						
Total CT		3,440	2,816						

COMBINED CYCLE									
		WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ERL	RELICENSING STATUS
Asheville	CT5	190	153	Arden, NC	Natural Gas/Oil	Base	0	N/A	N/A
Asheville	ST6	90	84	Arden, NC	Natural Gas/Oil	Base	0	N/A	N/A
Asheville	CT7	190	153	Arden, NC	Natural Gas/Oil	Base	0	N/A	N/A
Asheville	ST8	90	84	Arden, NC	Natural Gas/Oil	Base	0	N/A	N/A
Lee	CT1A	225	170	Goldsboro, NC	Natural Gas/Oil	Base	7	33	N/A
Lee	CT1B	227	170	Goldsboro, NC	Natural Gas/Oil	Base	7	33	N/A
Lee	CT1C	228	170	Goldsboro, NC	Natural Gas/Oil	Base	7	33	N/A
Lee	ST1	379	378	Goldsboro, NC	Natural Gas/Oil	Base	7	33	N/A
Smith <sup>4</sup>	CT7	194	154	Hamlet, NC	Natural Gas/Oil	Base	17	23	N/A
Smith <sup>4</sup>	CT8	194	154	Hamlet, NC	Natural Gas/Oil	Base	17	23	N/A
Smith <sup>4</sup>	ST4	182	169	Hamlet, NC	Natural Gas/Oil	Base	17	23	N/A
Smith <sup>4</sup>	CT9	216	180	Hamlet, NC	Natural Gas/Oil	Base	8	32	N/A
Smith <sup>4</sup>	CT10	216	180	Hamlet, NC	Natural Gas/Oil	Base	8	32	N/A
Smith <sup>4</sup>	ST5	248	248	Hamlet, NC	Natural Gas/Oil	Base	8	32	N/A
Sutton	CT1A	224	170	Wilmington, NC	Natural Gas/Oil	Base	6	34	N/A
Sutton	CT1B	224	171	Wilmington, NC	Natural Gas/Oil	Base	6	34	N/A
Sutton	ST1	<u>271</u>	<u>266</u>	Wilmington, NC	Natural Gas/Oil	Base	6	34	N/A
Total CC		3,588	3,054						

## HYDRO

	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Blewett	1	4	4	Lilesville, NC	Water	Intermediate	107	N/A	2055
Blewett	2	4	4	Lilesville, NC	Water	Intermediate	107	N/A	2055
Blewett	3	4	4	Lilesville, NC	Water	Intermediate	107	N/A	2055
Blewett	4	5	5	Lilesville, NC	Water	Intermediate	107	N/A	2055
Blewett	5	5	5	Lilesville, NC	Water	Intermediate	107	N/A	2055
Blewett	6	5	5	Lilesville, NC	Water	Intermediate	107	N/A	2055
Marshall	1	2	2	Marshall, NC	Water	Intermediate	34	N/A	Exempt
Marshall	2	2	2	Marshall, NC	Water	Intermediate	34	N/A	Exempt
Tillery	1	21	21	Mt. Gilead, NC	Water	Intermediate	91	N/A	2055
Tillery	2	18	18	Mt. Gilead, NC	Water	Intermediate	91	N/A	2055
Tillery	3	21	21	Mt. Gilead, NC	Water	Intermediate	91	N/A	2055
Tillery	4	24	24	Mt. Gilead, NC	Water	Intermediate	59	N/A	2055
Walters	1	36	36	Waterville, NC	Water	Intermediate	89	N/A	2034
Walters	2	40	40	Waterville, NC	Water	Intermediate	89	N/A	2034
Walters	3	36	36	Waterville, NC	Water	Intermediate	89	N/A	2034
Total Hydro		227	227						

NUCLEAR									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
Brunswick <sup>2</sup>	1	975	938	Southport, NC	Uranium	Base	42	37	2036
Brunswick <sup>2</sup>	2	953	932	Southport, NC	Uranium	Base	44	35	2034
Harris <sup>2</sup>	1	1009	964	New Hill, NC	Uranium	Base	32	47	2046
Robinson	2	<u>793</u>	<u>759</u>	Hartsville, SC	Uranium	Base	48	31	2030
Total NC		2,937	2,834						
Total SC		793	759						
Total Nuclear		3,730	3,593						

SOLAR									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ESTIMATED REMAINING LIFE	RELICENSING STATUS
NC Solar		141	141	NC	Solar	Intermittent	Various	N/A	N/A
Total Solar		141	141						

ENERGY STORAGE									
	UNIT	WINTER (MW)	SUMMER (MW)	LOCATION	FUEL TYPE	RESOURCE TYPE	AGE (YEARS)	ERL	RELICENSING STATUS
Asheville-Rock Hill		8.8	8.8	Asheville, NC	Energy Storage	Intermittent	0	N/A	N/A
Energy Storage Total		8.8	8.8						

TOTAL GENERATION CAPABILITY		
	WINTER CAPACITY (MW)	SUMMER CAPACITY (MW)
TOTAL DEP SYSTEM - N.C.	12,770	11,634
TOTAL DEP SYSTEM - S.C.	1,573	1,372
TOTAL DEP SYSTEM	14,343	13,006

**NOTE A:** Ratings reflect compliance with NERC reliability standards.

**NOTE B:** Duke Energy Progress completed the purchase from NCEMC of jointly owned Roxboro 4, Mayo 1, Brunswick 1 & 2 and Harris 1 units effective 7/31/2015.

**NOTE C:** Resource type based on NERC capacity factor classifications which may alternate over the forecast period.

**NOTE D:** Richmond County Plant renamed to Sherwood H. Smith Jr. Energy Complex.

**NOTE E:** Solar capacity ratings reflect nameplate winter and summer peak values.



PLANNED UPRATES			
UNIT	COMPLETION DATE	WINTER MW	SUMMER MW
Brunswick 1	Spring 2024	4	2
Brunswick 2	Spring 2027	6	4
Brunswick 2	Spring 2029	4	2
Brunswick 2	Spring 2029	6	4

NOTE: This capacity not reflected in unit ratings in above tables.

RETIREMENTS					
UNIT & PLANT NAME	LOCATION	CAPACITY (MW) WINTER / SUMMER		FUEL TYPE	RETIREMENT DATE
Asheville	Arden, NC	158	155	Coal	1/29/2020
Asheville	Arden, NC	192	189	Coal	1/29/2020
Cape Fear 5	Moncure, NC	148	144	Coal	10/1/12
Cape Fear 6	Moncure, NC	175	172	Coal	10/1/12
Cape Fear 1A	Moncure, NC	14	11	Combustion Turbine	3/31/13
Cape Fear 1B	Moncure, NC	14	12	Combustion Turbine	3/31/13
Cape Fear 2A	Moncure, NC	15	12	Combustion Turbine	3/31/13
Cape Fear 2B	Moncure, NC	14	11	Combustion Turbine	10/1/12
Cape Fear 1	Moncure, NC	12	11	Steam Turbine	3/31/11
Cape Fear 2	Moncure, NC	12	7	Steam Turbine	3/31/11
Darlington 5	Hartsville, SC	66	51	Combustion Turbine	5/31/18
Darlington 9	Hartsville, SC	65	50	Combustion Turbine	6/30/17
Darlington 11	Hartsville, SC	67	52	Combustion Turbine	11/8/15
Lee 1	Goldsboro, NC	80	74	Coal	9/15/12
Lee 2	Goldsboro, NC	80	68	Coal	9/15/12
Lee 3	Goldsboro, NC	252	240	Coal	9/15/12

RETIREMENTS (CONT.)					
UNIT & PLANT NAME	LOCATION	CAPACITY (MW) WINTER / SUMMER		FUEL TYPE	RETIREMENT DATE
Lee 1	Goldsboro, NC	15	12	Combustion Turbine	10/1/12
Lee 2	Goldsboro, NC	27	21	Combustion Turbine	10/1/12
Lee 3	Goldsboro, NC	27	21	Combustion Turbine	10/1/12
Lee 4	Goldsboro, NC	27	21	Combustion Turbine	10/1/12
Morehead 1	Morehead City, NC	15	12	Combustion Turbine	10/1/12
Robinson 1	Hartsville, SC	179	177	Coal	10/1/12
Robinson 1	Hartsville, SC	15	11	Combustion Turbine	3/31/13
Weatherspoon 1	Lumberton, NC	49	48	Coal	9/30/11
Weatherspoon 2	Lumberton, NC	49	48	Coal	9/30/11
Weatherspoon 3	Lumberton, NC	79	74	Coal	9/30/11
Sutton 1	Wilmington, NC	98	97	Coal	11/27/13
Sutton 2	Wilmington, NC	95	90	Coal	11/27/13
Sutton 3	Wilmington, NC	389	366	Coal	11/4/13
Sutton GT1	Wilmington, NC	12	11	Combustion Turbine	3/1/17
Sutton GTA	Wilmington, NC	31	23	Combustion Turbine	7/8/17
Sutton GTB	Wilmington, NC	<u>33</u>	<u>25</u>	Combustion Turbine	7/8/17
Total		2,504	2,316		

NOTE: This capacity not reflected in unit ratings in above tables.

PLANNING ASSUMPTIONS – UNIT RETIREMENTS <sup>a, b, c</sup>					
UNIT & PLANT NAME	LOCATION	WINTER CAPACITY (MW)	SUMMER CAPACITY (MW)	FUEL TYPE	EXPECTED RETIREMENT
Darlington 1	Hartsville, S.C.	63	50	Natural Gas/Oil	3/2020
Darlington 2	Hartsville, S.C.	64	48	Oil	3/2020
Darlington 3	Hartsville, S.C.	63	50	Natural Gas/Oil	3/2020
Darlington 4	Hartsville, S.C.	66	48	Oil	3/2020
Darlington 6	Hartsville, S.C.	62	43	Oil	3/2020
Darlington 7	Hartsville, S.C.	65	47	Natural Gas/Oil	3/2020
Darlington 8	Hartsville, S.C.	66	44	Oil	3/2020
Darlington 10	Hartsville, S.C.	65	49	Oil	3/2020
Mayo 1	Roxboro, N.C.	746	727	Coal	12/2028
Roxboro 1	Semora, N.C.	380	379	Coal	12/2028
Roxboro 2	Semora, N.C.	673	665	Coal	12/2028
Roxboro 3	Semora, N.C.	698	691	Coal	12/2027
Roxboro 4	Semora, N.C.	711	698	Coal	12/2027
Blewett 1	Lilesville, N.C.	17	13	Oil	12/2025
Blewett 2	Lilesville, N.C.	17	13	Oil	12/2025
Blewett 3	Lilesville, N.C.	65	13	Oil	12/2025
Blewett 4	Lilesville, N.C.	66	13	Oil	12/2025
Weatherspoon 1	Lumberton, N.C.	41	32	Natural Gas/Oil	12/2025
Weatherspoon 2	Lumberton, N.C.	41	32	Natural Gas/Oil	12/2025
Weatherspoon 3	Lumberton, N.C.	41	33	Natural Gas/Oil	12/2025
Weatherspoon 4	Lumberton, N.C.	<u>41</u>	<u>31</u>	Natural Gas/Oil	12/2025
Total		4,051	3,719		

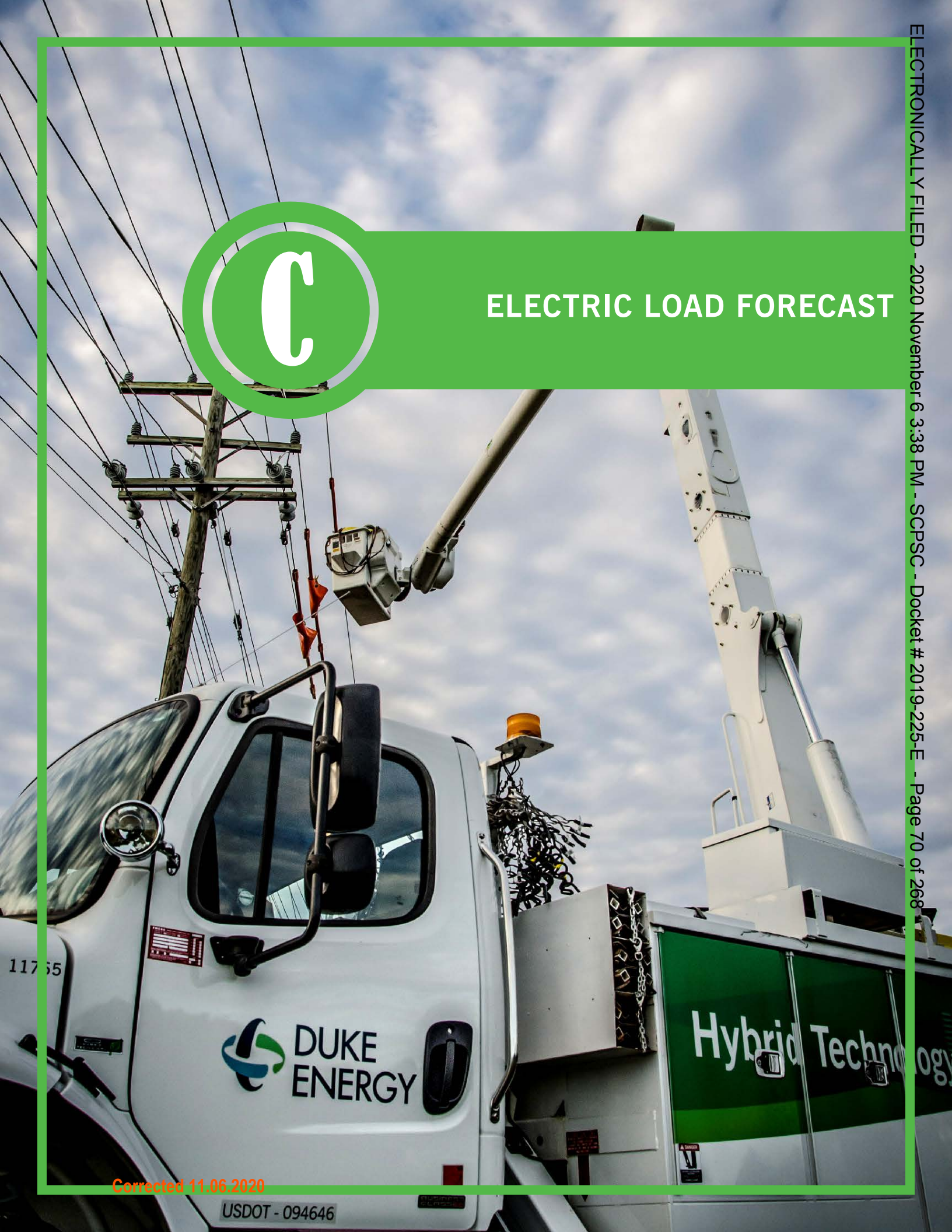
**NOTE a:** Retirement assumptions are for planning purposes only; Coal retirement dates represent the economic retirement dates determined in the Coal Retirement Analysis (as discussed in Chapter 11). Other technology units represent retirement dates based on the depreciation study approved as part of the most recent DEP rate case.

**NOTE b:** For planning purposes, all portfolios in the 2020 IRP assume subsequent license renewal for existing nuclear facilities beginning at end of current operating licenses.

**NOTE c:** Asheville coal units and Darlington CT units have been officially retired as of January 2020 and March 2020, respectively. Darlington CT units are included in this table as their retirement shows up in the Winter of 2021 in the LCR tables.



## ELECTRIC LOAD FORECAST



Corrected 11.06.2020

USDOT - 094646



## APPENDIX C: ELECTRIC LOAD FORECAST

### METHODOLOGY

The Duke Energy Progress Spring 2020 forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2021 – 2035 and represents the needs of the following customer classes:

#### DEP LOAD FORECAST CUSTOMER CLASSES



Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, along with weather, appliance efficiency trends, rooftop solar trends, and electric vehicle trends. Population is also used in the residential customer model.

The economic projections used in the Spring 2020 Forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the states of North and South Carolina. Moody's forecasts consist of economic and demographic projections, which are used in the energy and demand models.

The Spring 2020 forecast was developed using Moody's economic inputs as of January 2020. Therefore; the disruptions experienced due to COVID-19 are not incorporated in this forecast. DEP is continuing to monitor the impacts seen to both energies and peaks, and currently think that the longer-term impacts will be minimal. The Company will however continue to evaluate the impacts, and update future forecasts for expected impacts.

The Retail forecast consists of the three major classes: Residential, Commercial and Industrial. The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity prices and appliance efficiencies.

The usage per customer forecast was derived using a Statistical Adjusted End-Use Model (SAE). This is a regression-based framework that uses projected appliance saturation and efficiency trends developed by Itron using Energy Information Administration (EIA) data. It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models. The outlook for usage per customer is essentially flat through much of the forecast horizon, so most of the growth is primarily due to customer increases. The average annual growth rate of residential in the Spring 2020 forecast, including the impacts of Utility Energy Efficiency programs (UEE), rooftop solar and electric vehicles from 2021 – 2035 is 1.4%.

The Commercial forecast also uses an SAE model to reflect naturally occurring as well as government mandated efficiency changes. The three largest sectors in the commercial class are offices, education and retail. Commercial energy sales are expected to grow 0.1% per year over the forecast horizon. The Industrial class is forecasted by a standard econometric model, with drivers such as total manufacturing output and the price of electricity. Overall, Industrial sales are expected to decline 0.2% per year over the forecast horizon.

Weather impacts are incorporated into the models by using Heating Degree Days with a base temperature of 59 and Cooling Degree Days with a base temperature of 65. The forecast of degree days is based on a 30-year average, which is updated every year.

The appliance saturation and efficiency trends are developed by Itron using data from the Energy Information Administration (EIA). Itron is a recognized firm providing forecasting services to

the electric utility industry. These appliance trends are used in the residential and commercial sales models.

Peak demands were projected using the SAE approach. The peak forecast was developed using a monthly SAE model, similar to the sales SAE models, which includes monthly appliance saturations and efficiencies, interacted with weather and the fraction of each appliance type that is in use at the time of monthly peak.

## FORECAST ENHANCEMENTS

In 2013 the Company began using the SAE model projections to forecast sales and peaks. The end use models provide a better platform to recognize trends in equipment /appliance saturation and changes to efficiencies, and how those trends interact with heating, cooling, and “other” or non-weather-related sales. These appliance trends are used in the residential and commercial sales models. In conjunction with peer utilities and ITRON, the company continually looks for refinements to its modeling procedures to make better use of the forecasting tools and develop more reliable forecasts.

Each time the forecast is updated, the most currently available historical and projected data is used. The current 2020 forecast utilizes:

- Moody’s Analytics January 2020 base and consensus economic projections.
- End use equipment and appliance indexes reflect the 2019 update of ITRON’s end-use data, which is consistent with the Energy Information Administration’s 2019 Annual Energy Outlook.
- A calculation of normal weather using the period 1990-2019.

The Company also researches weather sensitivity of summer and winter peaks, peak history, hourly shaping of sales, and load research data in a continuous effort to improve forecast accuracy. As a result of continuous improvement efforts, refinements to peak history were identified during the Spring 2020 update, which lowered peak history. Peak history is a key driver in the peak forecast, so the revisions also contributed to the decrease in the peak forecast. Historical peaks and forecasted peaks can be viewed later in this appendix.



## ASSUMPTIONS

Below are the projected average annual growth rates of several key drivers from DEP's Spring 2020 Forecast.

**TABLE C-1  
KEY DRIVERS**

	2021-2035
Real Income	2.9%
Manufacturing Industrial Production Index (IPI)	1.1%
Population	1.5%

In addition to economic, demographic, and efficiency trends, the forecast also incorporates the expected impacts of UEE, as well as projected effects of electric vehicles and behind the meter solar technology.

## UTILITY ENERGY EFFICIENCY

Utility Energy Efficiency (UEE) Programs continue to have a large impact in the acceleration of the adoption of energy efficiency. When including the impacts of UEE on energy and peaks, careful attention must be paid to avoid the double counting of UEE efficiencies with the naturally occurring efficiencies included in the SAE modeling approach. To ensure there is not a double counting of these efficiencies, the forecast “rolls off” the UEE savings at the conclusion of its measure life. For example, if the accelerated benefit of a residential UEE program is expected to have occurred 7 years before the energy reduction program would have been otherwise adopted, then the UEE effects after year 7 are subtracted (“rolled off”) from the total cumulative UEE. With the SAE model’s framework, the naturally occurring appliance efficiency trends replace the rolled off UEE benefits serving to continue to reduce the forecasted load resulting from energy efficiency adoption.

The table below illustrates this process on sales:

**TABLE C-2**  
**UEE PROGRAM LIFE PROCESS (GWH)**

YEAR	FORECAST BEFORE UEE	HISTORICAL UEE ROLL OFF	FORECAST WITH HISTORICAL ROLL OFF	FORECASTED UEE INCREMENTAL ROLL ON	FORECASTED UEE INCREMENTAL ROLL OFF	UEE TO SUBTRACT FROM FORECAST	FORECAST AFTER UEE
2021	63,726	5	63,731	(651)	309	(342)	63,389
2022	64,097	20	64,117	(1,013)	464	(549)	63,568
2023	64,476	49	64,525	(1,367)	619	(749)	63,776
2024	64,996	101	65,097	(1,713)	774	(940)	64,157
2025	65,423	177	65,600	(2,054)	929	(1,125)	64,475
2026	65,924	268	66,192	(2,382)	1,085	(1,297)	64,895
2027	66,453	371	66,824	(2,688)	1,243	(1,445)	65,379
2028	67,066	473	67,538	(2,973)	1,404	(1,569)	65,969
2029	67,601	558	68,159	(3,236)	1,586	(1,650)	66,509
2030	68,159	622	68,781	(3,477)	1,807	(1,670)	67,111
2031	68,746	666	69,412	(3,699)	2,041	(1,659)	67,754
2032	69,382	688	70,070	(3,912)	2,277	(1,635)	68,435
2033	69,956	698	70,655	(4,124)	2,528	(1,595)	69,059
2034	70,574	702	71,276	(4,334)	2,784	(1,550)	69,726
2035	71,223	702	71,925	(4,543)	3,064	(1,479)	70,446

## ROOFTOP SOLAR AND ELECTRIC VEHICLES

Rooftop solar photovoltaic (PV) and electric vehicles (EVs) are considered load modifiers: behind-the-meter solar PV generation reduces the effective load that Duke Energy serves, while plug-in EV charging increases load on the system. Rooftop solar generation and EV load are forecasted independently and then combined with base load and UEE impacts to produce the final electric load forecast. Impacts from existing rooftop solar and EVs are embedded in the historical data that the base load forecast is derived from. Therefore, forecasts for rooftop solar and EVs include impacts from only incremental or “net new” resources projected to be added within the planning horizon.

With the variable characteristics of solar generation and mobility of EVs, utilities will need to employ advanced system controls and/or time-of-use incentives for optimal grid management in order to provide safe, reliable and cost-effective service to customers. Given that DEP does not currently have dispatch control of rooftop solar or EVs, DEP’s load forecast accounts for the variability of uncontrolled

generation and charging. If advanced controls are employed in the future, the forecasted shape would better align with system capabilities and needs.

The markets for rooftop solar and EVs are growing rapidly, so it will become increasingly important to understand and accurately forecast their impacts on electric load. Additional discussion related to regulatory policy and technology can be found in Appendix E.

## ROOFTOP SOLAR

Rooftop solar refers to behind-the-meter solar PV generation for residential, commercial and industrial customers. Energy produced by the solar array is consumed by the customer, offsetting their demand on the electric grid. Any excess energy is exported to the grid and credited to the customer at full retail rates under current net energy metering (NEM) policies in North and South Carolina. Both NC and SC have requirements to revisit their NEM tariffs, so while DEP assumes there will be changes to the current program within the planning horizon, it is not yet clear what those changes may be. For this IRP, DEP assumes that NEM tariffs will evolve to more closely align with the cost to serve rooftop solar customers, such that bill savings would gradually decrease over time. This reduction is offset by declining technology costs and increased customer preferences for self-generation, leading to a forecasted net increase in rooftop solar adoption.

Rooftop solar exports are beneficial as a source of carbon-free energy, but present challenges for grid operators due to intermittency associated with solar generation, reduced visibility of the resource and lack of control of energy supply.

Under full retail net metering policy, rooftop solar systems have typically been sized to offset 100% of a customer's annual average demand, within the constraints of state policy. Residential customers are limited to 20 kW-AC, and non-residential customers are limited to the lesser of 1 MW-AC or 100% demand per NC HB 589 and SC Act 62.

**TABLE C-3**  
**AVERAGE ROOFTOP SOLAR CAPACITY (KW-AC)**

CUSTOMER CLASS	DEP-NC	DEP-SC
Residential	6.4	7.7
Non-Residential	60	158

The rooftop solar generation forecast is derived from a series of capacity forecasts and hourly production profiles tailored to residential, commercial and industrial customer classes.

Each capacity forecast is the product of a customer adoption forecast and an average capacity value. Adoption forecasts are based on linear regression modeling in Itron MetrixND using customer payback period as the primary independent variable. Payback periods are a function of installed cost, regulatory incentives and electric bill savings. Historical and projected technology costs are provided by Navigant. Projected incentives and bill savings are based on current regulatory policies and input from internal subject matter experts. Average capacity values are based on trends in historical adoption.

Hourly production profiles have “12x24” resolution meaning there is one 24-hour profile for each month. Profiles are derived from actual production data, where available, and solar PV modeling. Modeling is performed in PVsyst using over 20 years of historical irradiance data from Solar Anywhere and Solcast. Models are created for 9 irradiance locations across DEP’s service area and 21 tilt/azimuth configurations. Results are combined on a weighted average basis to produce final profiles.

Table C-4 shows the projected incremental additions of rooftop solar customers, along with the impacts on capacity and energy, in NC and SC, at the beginning and end of the planning horizon.

**TABLE C-4**  
**ROOFTOP SOLAR, NET NEW FROM 2020**

YEAR	STATE	NUMBER OF CUSTOMERS	PERCENT OF CUSTOMERS	CAPACITY (MW)	ENERGY (MWH/YEAR)
2021	NC	9,000	0.6%	79	83,000
	SC	1,400	0.8%	14	13,000
2035	NC	64,200	3.8%	550	722,000
	SC	11,400	5.5%	114	141,000

## ELECTRIC VEHICLES

EV charging represents a significant opportunity for load growth in the planning horizon. Wood Mackenzie projects EV charging infrastructure to nearly quintuple by 2025<sup>1</sup>, and BloombergNEF projects EVs to increase U.S. load by 2% in 2030 and 10% in 2040<sup>2</sup>.

Duke Energy's EV load forecast is derived from a series of EV forecasts and load profiles.

The Electric Power Research Institute (EPRI) provides EV forecasts specific to DEP's service area for three adoption cases (low, medium and high) and five vehicle types. In recent years Duke Energy has used EPRI's medium adoption case with minor adjustments as needed for known or expected changes in the market. Vehicle types include plug-in EVs with 10-, 20- and 40-mile range and fully electric vehicles with 100 and 250-mile range.

Unique hourly load profiles (kWh per vehicle per day) are developed internally for each vehicle type, for weekdays and weekends, and for residential and public charging.

Table C-5 shows the projected incremental additions of EVs in operation, along with the impacts on energy, at the beginning and end of the planning horizon.

<sup>1</sup> Wood Mackenzie: US DER Outlook (June 2020).

<sup>2</sup> BloombergNEF: 2020 Electric Vehicle Outlook: U.S. Update (June 2020).

TABLE C-5

# ELECTRIC VEHICLES, NET NEW FROM 2020, INCLUDES NC AND SC

YEAR	EVS IN OPERATION	PERCENT OF VEHICLE FLEET	LOAD (MWH/YEAR)
2021	13,900	0.2%	17,000
2035	241,200	8.1%	856,000

## NET IMPACT OF ROOFTOP SOLAR AND ELECTRIC VEHICLES

Figures C-1, C-2 and C-3 illustrate the impacts on annual energy, winter peak demand and summer peak demand from rooftop solar and EVs by customer class across the planning horizon.

FIGURE C-1

## PERCENT IMPACT OF PV AND EV ON ANNUAL LOAD, NET NEW FROM 2020

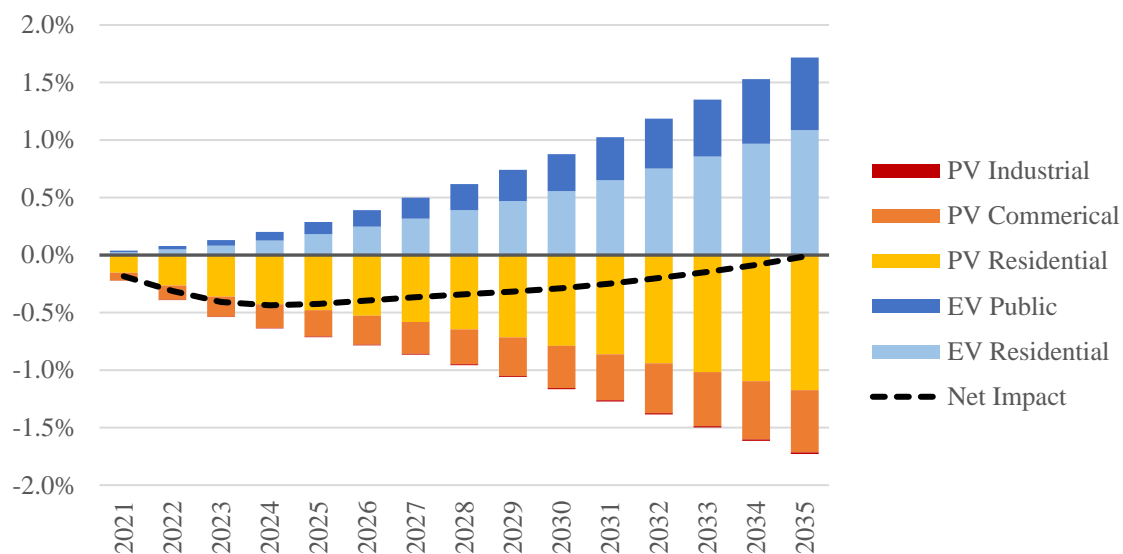


FIGURE C-2

PERCENT IMPACT OF PV AND EV ON WINTER PEAK LOAD, NET NEW FROM 2020

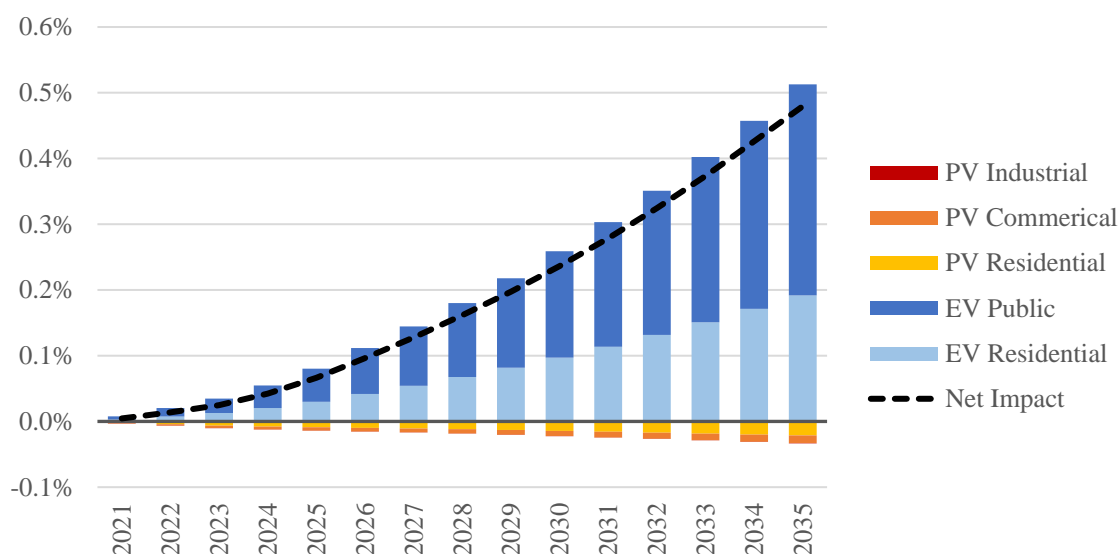
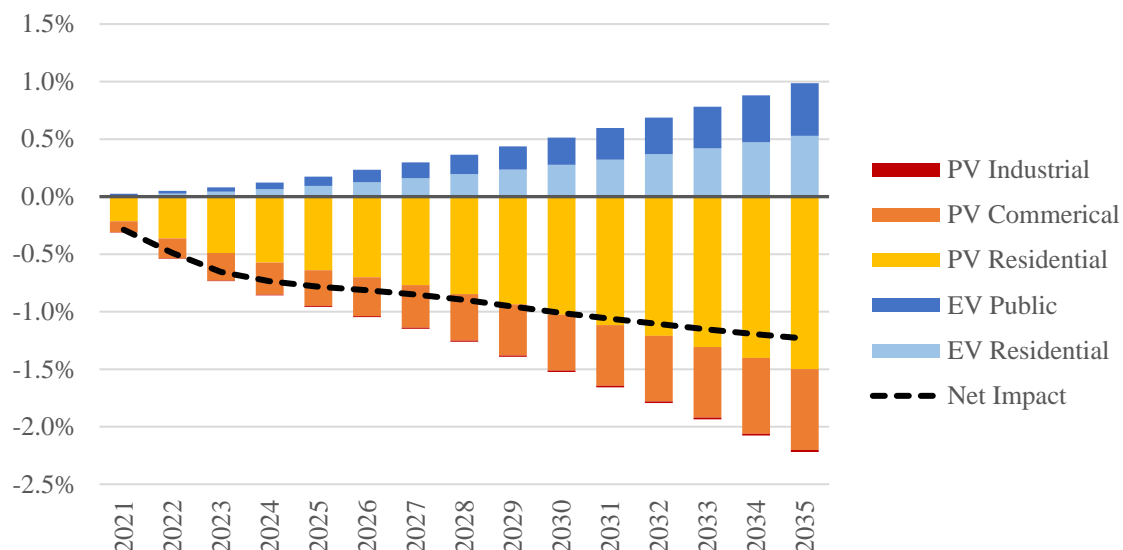


FIGURE C-3

PERCENT IMPACT OF PV AND EV ON SUMMER PEAK LOAD, NET NEW FROM 2020





## CUSTOMER GROWTH

Tables C-6 and C-7 show the history and projections for DEP customers

**TABLE C-6**

### RETAIL CUSTOMERS (ANNUAL AVERAGE IN THOUSANDS)

YEAR	RESIDENTIAL CUSTOMERS	COMMERCIAL CUSTOMERS	INDUSTRIAL CUSTOMERS	OTHER CUSTOMERS	RETAIL CUSTOMERS
2010	1,216	216	5	2	1,439
2011	1,221	217	4	2	1,445
2012	1,231	219	4	2	1,457
2013	1,242	222	4	2	1,470
2014	1,257	223	4	2	1,486
2015	1,275	226	4	2	1,507
2016	1,292	229	4	2	1,527
2017	1,310	232	4	1	1,547
2018	1,331	235	4	1	1,571
2019	1,349	237	4	1	1,591
Avg. Annual Growth Rate	1.2%	1.0%	-1.4%	-7.8%	1.1%

TABLE C-7

## RETAIL CUSTOMERS (THOUSANDS, ANNUAL AVERAGE)

YEAR	RESIDENTIAL CUSTOMERS	COMMERCIAL CUSTOMERS	INDUSTRIAL CUSTOMERS	OTHER CUSTOMERS	RETAIL CUSTOMERS
2021	1,388	239	4	1	1,632
2022	1,406	240	4	1	1,652
2023	1,423	242	4	1	1,670
2024	1,441	243	4	1	1,689
2025	1,458	244	4	1	1,708
2026	1,475	245	4	1	1,725
2027	1,492	246	4	1	1,743
2028	1,509	247	4	1	1,762
2029	1,527	248	4	1	1,780
2030	1,545	249	4	1	1,799
2031	1,564	250	4	1	1,819
2032	1,582	251	4	1	1,838
2033	1,601	251	4	1	1,858
2034	1,619	252	4	1	1,877
2035	1,638	253	4	1	1,896
Avg. Annual Growth Rate	1.2%	0.4%	-0.3%	0.0%	1.1%

## ELECTRICITY SALES

Table C-8 shows the actual historical gigawatt hour (GWh) sales. As a note, the values in Table C-8 are not weather adjusted Sales.

**TABLE C-8**  
**ELECTRICITY SALES (GWH)**

YEAR	RESIDENTIAL GWH	COMMERCIAL GWH	INDUSTRIAL GWH	MILITARY & OTHER GWH	RETAIL GWH	WHOLESALE GWH	TOTAL SYSTEM GWH
2010	17,117	13,639	10,375	1,497	42,628	12,772	55,400
2011	19,108	14,184	10,677	1,574	45,544	12,772	58,316
2012	17,764	13,709	10,573	1,591	43,637	12,267	55,903
2013	16,663	13,581	10,508	1,602	42,355	12,676	55,031
2014	18,201	13,887	10,321	1,614	44,023	13,578	57,601
2015	17,954	14,039	10,288	1,597	43,876	15,782	59,658
2016	17,686	14,082	10,274	1,563	43,606	18,676	62,282
2017	17,228	13,903	10,391	1,531	43,053	18,242	61,295
2018	18,939	14,219	10,475	1,560	45,194	19,331	64,525
2019	18,177	13,992	10,534	1,537	44,241	18,694	62,935
Avg. Annual Growth Rate	0.7%	0.3%	0.2%	0.3%	0.4%	4.3%	1.4%

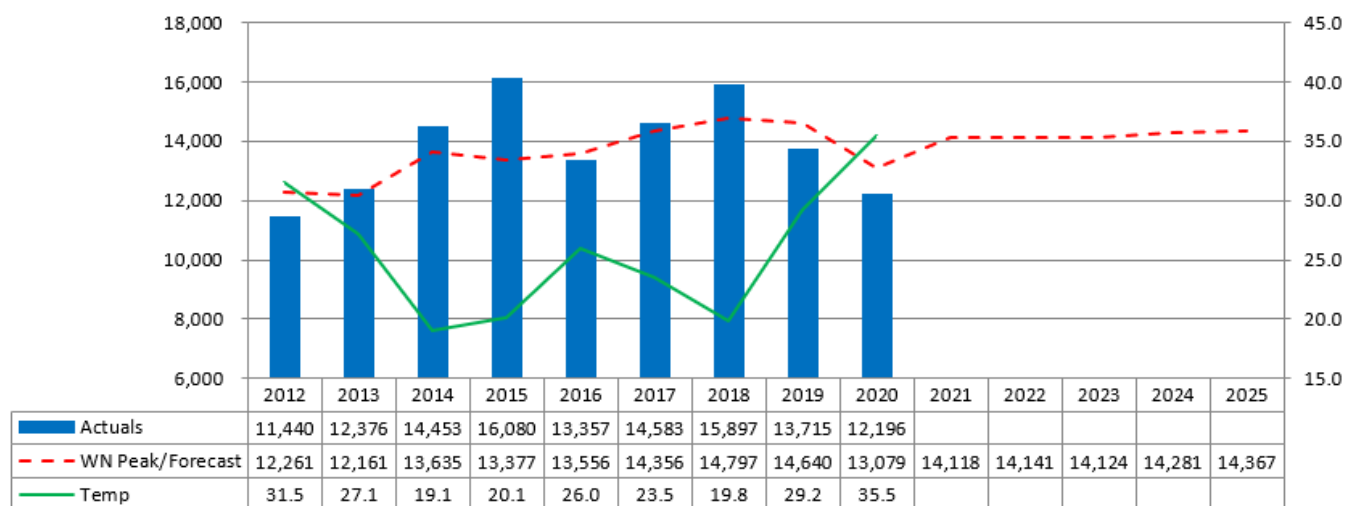
NOTE: The wholesale values in Table C-8 exclude NCEMPA sales for all years before 2015 and is only partially included in 2015.

## SYSTEM PEAKS

Figures C-4 and C-5 show the historical actual and weather normalized peaks for the system:

FIGURE C-4

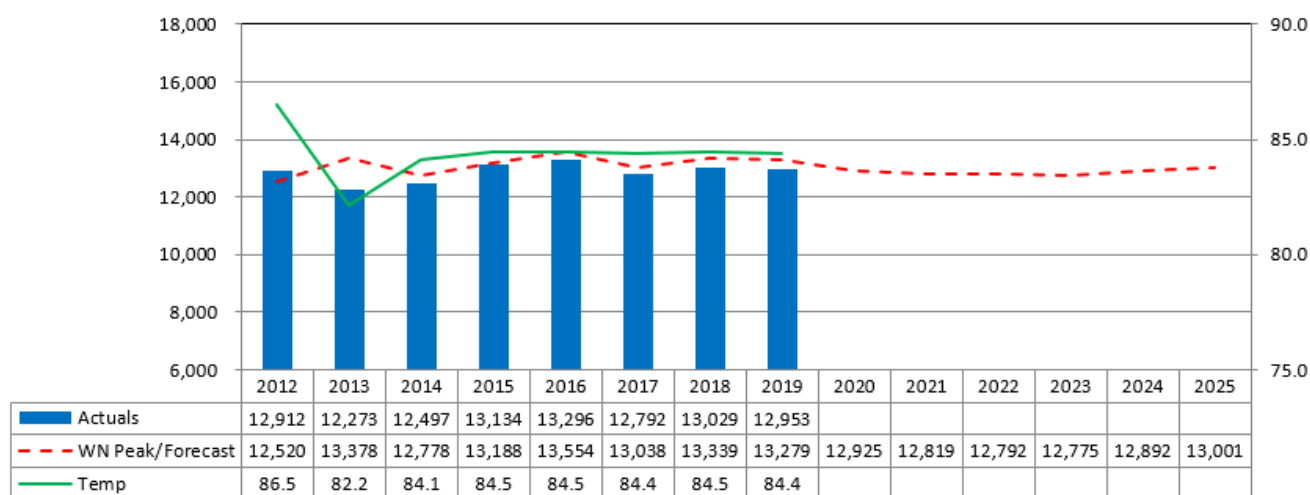
## DEP ACTUALS, WEATHER NORMAL AND FORECASTED WINTER PEAKS



NOTE: WN Peak/Forecast values in years 2021-2025 are forecasted peak values from the 2020 Spring Forecast. The Temperatures are the average daily temperature on the day of the peak

FIGURE C-5

## DEP ACTUAL AND WEATHER NORMAL AND FORECASTED SUMMER PEAKS



NOTE: WN Peak/Forecast values in years 2020-2025 are forecasted peak values from the 2020 Spring Forecast. The Temperatures are the average daily temperature on the day of the peak.

## FORECAST RESULTS

A tabulation of the utility's sales and peak forecasts are shown as charts below:

- Table C-9: Forecasted energy sales by class (Including the impacts of UEE, rooftop solar, and electric vehicles)
- Table C-10: Forecast energy sales – gross load to net load (walkthrough of impacts from UEE, rooftop solar, electric vehicles and voltage control program)
- Table C-11: Summary of the load forecast without UEE programs and excluding any impacts from demand reduction programs
- Table C-12: Summary of the load forecast with UEE programs and excluding any impacts from demand reduction programs

These projections include Wholesale, and all the loads and energy in the tables and charts below are at generation, except for the class sales forecast, which is at the meter.

Load duration curves, with and without UEE programs are shown as Figures C-6 and C-7.

The values in these tables reflect the loads that Duke Energy Progress is contractually obligated to provide and cover the period from 2021 to 2035.

**TABLE C-9**  
**FORECASTED ENERGY SALES BY CLASS**

YEAR	RESIDENTIAL GWH	COMMERCIAL GWH	INDUSTRIAL GWH	OTHER GWH	RETAIL GWH
2021	18,183	13,931	10,424	1,539	44,077
2022	18,303	13,905	10,323	1,530	44,061
2023	18,459	13,874	10,223	1,521	44,077
2024	18,668	13,871	10,160	1,514	44,214
2025	18,893	13,866	10,129	1,506	44,394
2026	19,144	13,873	10,089	1,499	44,606
2027	19,412	13,891	10,086	1,493	44,882
2028	19,705	13,920	10,105	1,489	45,219
2029	20,006	13,954	10,130	1,485	45,575
2030	20,343	13,996	10,153	1,481	45,973
2031	20,701	14,042	10,179	1,478	46,401
2032	21,081	14,086	10,183	1,475	46,826
2033	21,455	14,129	10,180	1,471	47,235
2034	21,844	14,178	10,172	1,469	47,662
2035	22,236	14,240	10,187	1,467	48,131
Avg. Annual Growth Rate	1.4%	0.2%	-0.2%	-0.3%	0.6%

NOTE: Values are at meter.

TABLE C-10

# FORECASTED ENERGY SALES – GROSS LOAD TO NET LOAD

YEAR	GROSS RETAIL SALES	ENERGY EFFICIENCY	ROOFTOP SOLAR	ELECTRIC VEHICLES	VOLTAGE CONTROL (IVVC)	NET RETAIL SALES
2021	44,498	(342)	(96)	17		44,077
2022	44,746	(549)	(170)	35		44,061
2023	45,013	(749)	(236)	57	(8)	44,077
2024	45,363	(940)	(282)	89	(17)	44,214
2025	45,792	(1,125)	(318)	129	(83)	44,394
2026	46,165	(1,297)	(354)	176	(83)	44,606
2027	46,578	(1,445)	(394)	227	(84)	44,882
2028	47,029	(1,569)	(441)	284	(84)	45,219
2029	47,457	(1,650)	(493)	345	(85)	45,575
2030	47,864	(1,670)	(548)	413	(85)	45,973
2031	48,263	(1,659)	(605)	488	(86)	46,401
2032	48,643	(1,635)	(667)	571	(87)	46,826
2033	48,989	(1,595)	(729)	657	(87)	47,235
2034	49,342	(1,550)	(795)	753	(88)	47,662
2035	49,704	(1,479)	(862)	856	(88)	48,131

NOTE: Values are at meter.



TABLE C-11

**SUMMARY OF THE LOAD FORECAST WITHOUT UEE PROGRAMS AND  
EXCLUDING ANY IMPACTS FROM DEMAND REDUCTION PROGRAMS**

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2021	12,885	14,161	63,731
2022	12,909	14,221	64,117
2023	12,913	14,240	64,525
2024	13,063	14,431	65,097
2025	13,207	14,566	65,600
2026	13,381	14,670	66,192
2027	13,461	14,867	66,824
2028	13,589	14,998	67,538
2029	13,833	15,248	68,159
2030	13,917	15,310	68,781
2031	14,075	15,506	69,412
2032	14,241	15,672	70,070
2033	14,361	15,792	70,655
2034	14,499	15,920	71,276
2035	14,757	16,210	71,925
Avg. Annual Growth Rate	1.0%	1.0%	0.9%

FIGURE C-6  
LOAD DURATION CURVE WITHOUT ENERGY EFFICIENCY PROGRAMS AND BEFORE DEMAND  
RESPONSE PROGRAMS

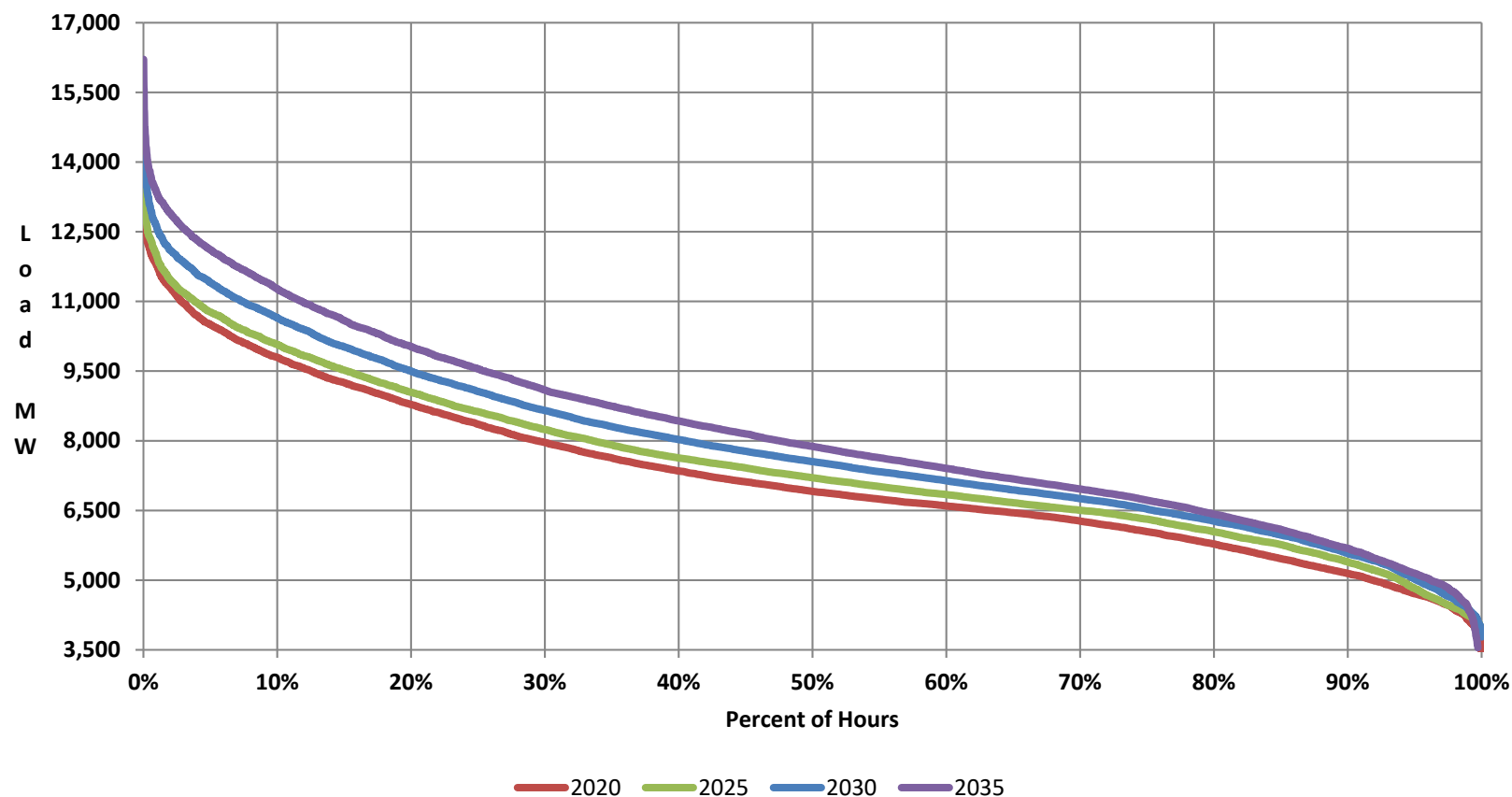


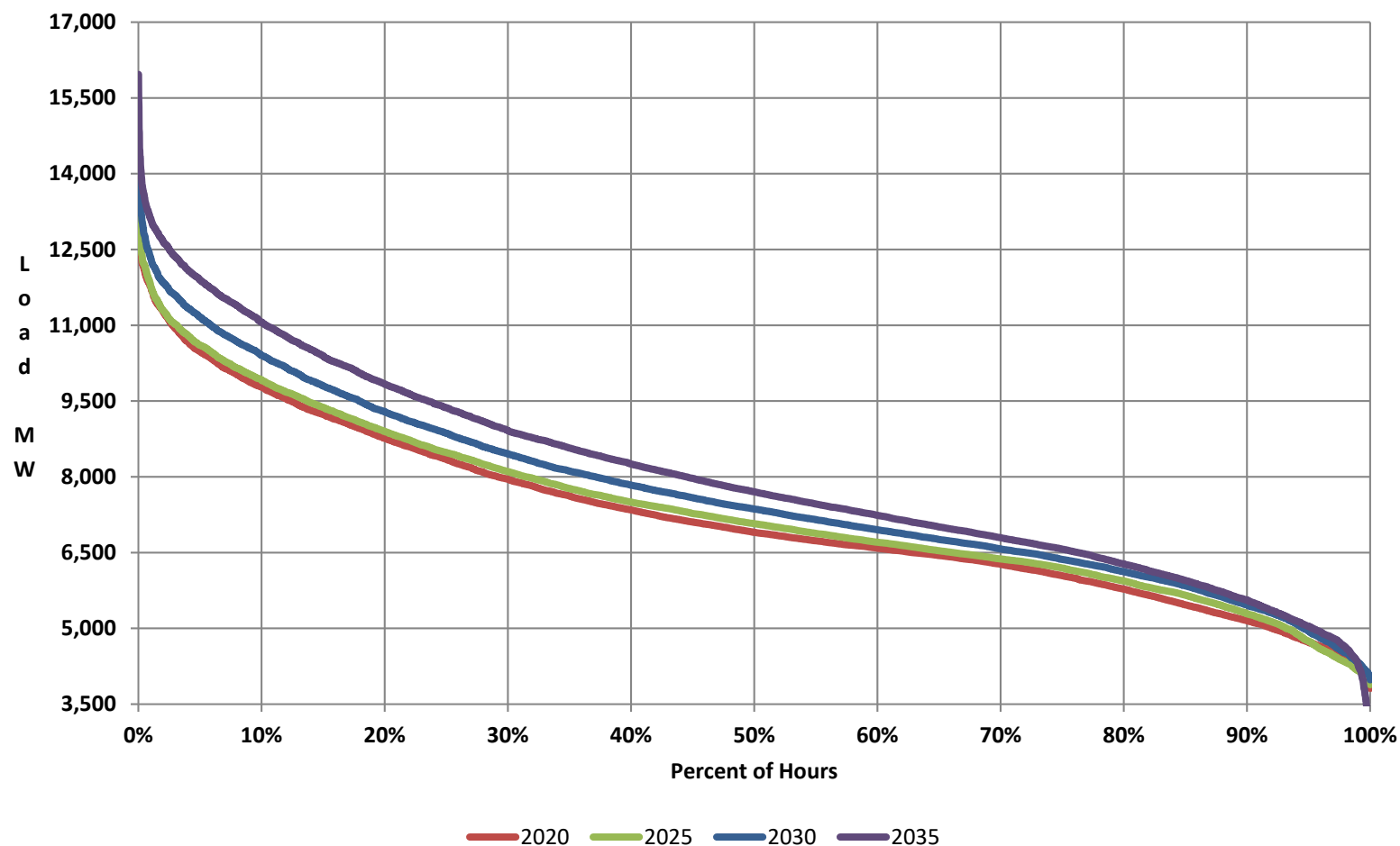
TABLE C-12

SUMMARY OF THE LOAD FORECAST WITH UEE PROGRAMS AND  
EXCLUDING ANY IMPACTS FROM DEMAND REDUCTION PROGRAMS

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2021	12,818	14,118	63,389
2022	12,807	14,143	63,568
2023	12,780	14,130	63,776
2024	12,901	14,290	64,157
2025	13,016	14,381	64,475
2026	13,161	14,456	64,895
2027	13,216	14,629	65,379
2028	13,324	14,740	65,969
2029	13,552	14,976	66,509
2030	13,649	15,035	67,111
2031	13,810	15,233	67,754
2032	13,959	15,404	68,435
2033	14,107	15,531	69,059
2034	14,252	15,666	69,726
2035	14,520	15,966	70,446
Avg. Annual Growth Rate	0.9%	0.9%	0.8%

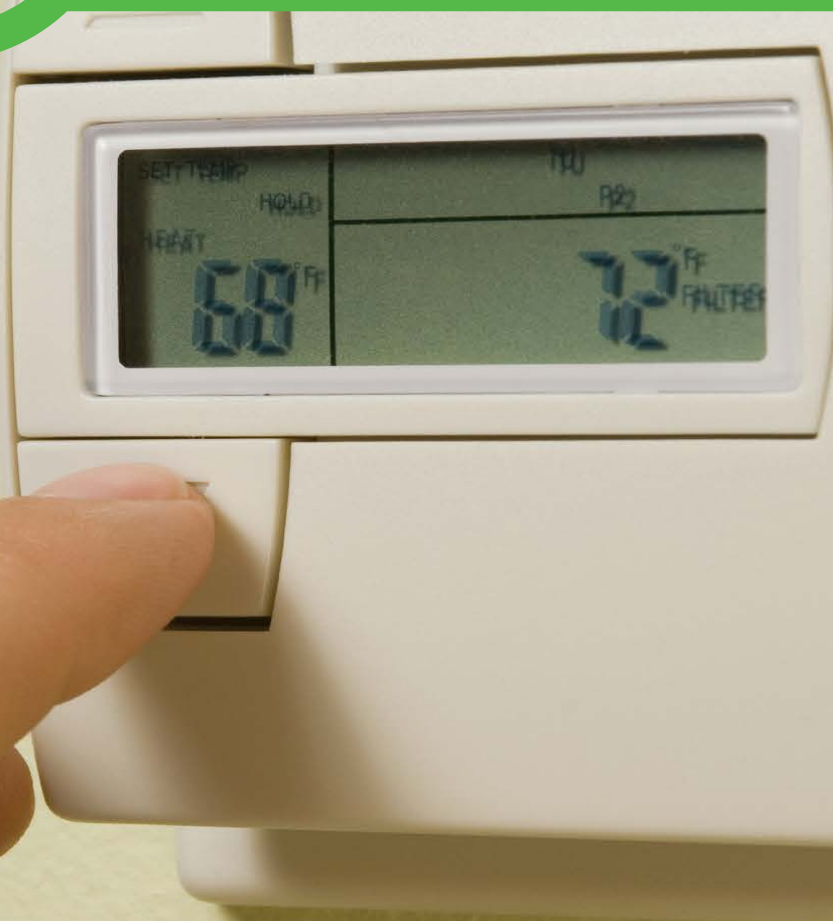
NOTE: Values are at generation level. Values differ from Tables 12-E and 12-F due to 150 MW firm sale in years 2021 – 2024.

FIGURE C-7  
LOAD DURATION CURVE WITH ENERGY EFFICIENCY PROGRAMS & BEFORE DEMAND RESPONSE PROGRAMS



D

## ENERGY EFFICIENCY, DEMAND SIDE MANAGEMENT AND VOLTAGE OPTIMIZATION



## APPENDIX D: ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

### DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS:

DEP continues to pursue a long-term, balanced capacity and energy strategy to meet the future electricity needs of its customers. This balanced strategy includes a strong commitment to demand-side management (DSM) and energy efficiency (EE) programs, investments in renewable and emerging energy technologies, and state-of-the art power plants and delivery systems.

DEP uses EE and DSM programs in its IRP to efficiently and cost-effectively alter customer demands and reduce the long-run supply costs for energy and peak demand. These programs can vary greatly in their dispatch characteristics, size and duration of load response, certainty of load response, and level and frequency of customer participation. In general, programs are offered in two primary categories: EE programs that reduce energy consumption and DSM programs that reduce peak demand (demand-side management or demand response programs and certain rate structure programs).

Following are the EE and DSM programs currently available through DEP as of December 31, 2019:

				
RESIDENTIAL EE PROGRAMS	NON-RESIDENTIAL EE PROGRAMS	COMBINED RESIDENTIAL / NON-RESIDENTIAL EE PROGRAMS	RESIDENTIAL DSM PROGRAMS	NON-RESIDENTIAL DSM PROGRAMS
Energy Efficient Appliances and Devices	Non-Residential Smart \$aver® Energy Efficient Products and Assessment	Energy Efficient Lighting	EnergyWise <sup>SM</sup> Home	CIG Demand Response Automation
Energy Efficiency Education	Non-Residential Smart \$aver® Performance Incentive	Distribution System Demand Response (DSDR)		Large Load Curtailable Rates & Riders
Multi-Family Energy Efficiency	Small Business Energy Saver			EnergyWise® Business
My Home Energy Report				
Neighborhood Energy Saver (Low-Income)				
Residential Energy Assessments				
Residential New Construction				
Residential Smart \$aver® Energy Efficiency				



## ENERGY EFFICIENCY PROGRAMS

Energy Efficiency programs are typically non-dispatchable education or incentive-based programs. Energy and capacity savings are achieved by changing customer behavior or through the installation of more energy-efficient equipment or structures. All cumulative effects (gross of Free Riders, at the Plant<sup>1</sup>) since the inception of these existing programs through the end of 2019 are summarized below. Please note that the cumulative impacts listed below include the impact of any Measurement and Verification performed since program inception and also note that a “Participant” in the information included below is based on the unit of measure for the specific energy efficiency measure (e.g. number of bulbs, kWh of savings, tons of refrigeration, etc.), and may not be the same as the number of customers that actually participate in these programs. The following provides more detail on DEP’s existing EE programs.

### RESIDENTIAL EE PROGRAMS

#### Energy Efficient Appliances and Devices Program

The Energy Efficient Appliances and Devices Program is a new program that combines DEP’s previous “Save Energy and Water Kit” with a variety of high efficiency products available through the Company’s Online Savings Store, including but not limited to Air Purifiers, Dehumidifiers and LED Fixtures. The Save Energy and Water kit offers low flow water fixtures and insulating pipe tape to residential single-family homeowners with electric water heaters. Program participants are eligible for one kit shipped free of charge to their home. Kits are available in two sizes for homes with one or more full bathrooms and contain varying quantities of shower heads, bathroom aerators, kitchen aerator and insulating pipe tape.

APPLIANCES AND DEVICES				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	1,311,635	78,693	25,278	21,285

<sup>1</sup> “Gross of Free Riders” means that the impacts associated with the EE programs have not been reduced for the impact of Free Riders. “At the Plant” means that the impacts associated with the EE programs have been increased to include line losses.

## ENERGY EFFICIENCY EDUCATION PROGRAM

The Energy Efficiency Education Program is an energy efficiency program available to students in grades K-12 enrolled in public and private schools who reside in households served by Duke Energy Progress. The Program provides principals and teachers with an innovative curriculum that educates students about energy, resources, how energy and resources are related, ways energy is wasted and how to be more energy efficient. The centerpiece of the current curriculum is a live theatrical production performed by two professional actors that is focused on concepts such as energy, renewable fuels and energy efficiency.

Following the performance, students are encouraged to complete a home energy survey with their family to receive an Energy Efficiency Starter Kit. The kit contains specific energy efficiency measures to reduce home energy consumption and is available at no cost to student households at participating schools. Teachers receive supportive educational material for classroom and student take home assignments. The workbooks, assignments and activities meet state curriculum requirements.

ENERGY EDUCATION PROGRAM FOR SCHOOLS				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	47,949	14,849	4,854	2,056

## MULTI-FAMILY ENERGY EFFICIENCY PROGRAM

The Multi-Family Energy Efficiency Program provides energy efficient lighting and water measures to reduce energy usage in eligible multi-family properties. The Program allows Duke Energy Progress to target multi-family apartment complexes with an alternative delivery channel. The measures are installed in permanent fixtures by the program administrator or the property management staff. The program offers LEDs including A-Line, Globes and Candelabra bulbs and energy efficient water measures such as bath and kitchen faucet aerators, water saving showerheads and pipe wrap.

MULTI-FAMILY ENERGY EFFICIENCY				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	1,459,233	75,502	9,400	7,384

## MY HOME ENERGY REPORT PROGRAM

The My Home Energy Report (MyHER) Program provides residential customers with a comparative usage report that engages and motivates customers by comparing energy use to similar residences in the same geographical area based upon the age, size and heating source of the home. The report also empowers customers to become more efficient by providing them with specific energy saving recommendations to improve the efficiency of their homes. The actionable energy savings tips, as well as measure-specific coupons, rebates or other Company program offers that may be included in a customer's report are based on that specific customer's energy profile.

The program includes an interactive online portal that allows customers to further engage and learn more about their energy use and opportunities to reduce usage. Electronic versions of the My Home Energy Report are sent to customers enrolled on the portal. In addition, all MyHER customers with an email address on file with the Company receive an electronic version of their report monthly.

MY HOME ENERGY REPORT				
CAPABILITY AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	769,490	154,602	54,248	42,160

## NEIGHBORHOOD ENERGY SAVER (LOW-INCOME) PROGRAM

DEP's Neighborhood Energy Saver Program reduces energy usage through the direct installation of energy efficiency measures within the households of income qualifying residential customers. The Program utilizes a Company-selected vendor to: (1) provide an on-site energy assessment of the residence to identify appropriate energy conservation measures, (2) install a comprehensive package of energy conservation measures at no cost to the customer, and (3) provide one-on-one energy education. Program measures address end-uses in lighting, refrigeration, air infiltration and HVAC applications.

Program participants receive a free energy assessment of their home followed by a recommendation of energy efficiency measures to be installed at no cost to the resident. A team of energy technicians will install applicable measures and provide one-on-one energy education about each measure emphasizing the benefit of each and recommending behavior changes to reduce and control energy usage.

NEIGHBORHOOD ENERGY SAVER				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	46,842	25,717	3,626	1,356

## RESIDENTIAL ENERGY ASSESSMENTS PROGRAM

The Residential Energy Assessments Program provides eligible customers with a free in-home energy assessment, performed by a Building Performance Institute (BPI) certified energy specialist and designed to help customers reduce energy usage and save money. The BPI certified energy specialist completes a 60 to 90-minute walk through assessment of a customer's home and analyzes energy usage to identify energy savings opportunities. The energy specialist discusses behavioral and equipment modifications that can save energy and money with the customer. The customer also receives a customized report that identifies actions the customer can take to increase their home's efficiency.

In addition to a customized report, customers receive an energy efficiency starter kit with a variety of measures that can be directly installed by the energy specialist. The kit includes measures such as energy efficient lighting, low flow shower head, low flow faucet aerators, outlet/switch gaskets, weather stripping and an energy saving tips booklet. Additional energy efficient bulbs are available to be installed by the auditor if needed.

RESIDENTIAL ENERGY ASSESSMENTS				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	144,853	31,026	3,787	2,939

## RESIDENTIAL NEW CONSTRUCTION PROGRAM

The Residential New Construction Program provides incentives for new single family and multi-family residential dwellings (projects of three stories and less) that fall within the 2018 North Carolina Residential Building Code to meet or exceed the 2018 North Carolina Energy Conservation Code High Efficiency Residential Option (HERO). If a builder or developer constructing to the HERO standard elects to participate, the Program offers the homebuyer an incentive guaranteeing the heating and cooling

consumption of the dwelling's total annual energy costs. Additionally, the Program incents the installation of high-efficiency heating ventilating and air conditioning (HVAC) and heat pump water heating (HPWH) equipment in new single family, manufactured, and multi-family residential housing units.

New construction represents a unique opportunity for capturing cost effective EE savings by encouraging the investment in energy efficiency features that would otherwise be impractical or costlier to install at a later time.

RESIDENTIAL NEW CONSTRUCTION				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	39,880,246	60,788	23,231	21,201

NOTE: The participants and impacts are from both the Residential New Construction program and the previous Home Advantage program.

## RESIDENTIAL SMART \$AVER® EE PROGRAM (FORMERLY KNOWN AS THE HOME ENERGY IMPROVEMENT PROGRAM)

The Residential Smart \$aver® EE Program offers DEP customers a variety of energy conservation measures designed to increase energy efficiency in existing residential dwellings. The Program utilizes a network of participating contractors to encourage the installation of: (1) high efficiency central air conditioning (AC) and heat pump systems with optional add on measures such as Quality Installation and Smart Thermostats, (2) attic insulation and sealing, (3) heat pump water heaters, and (4) high efficiency variable speed pool pumps.

The prescriptive menu of energy efficiency measures provided by the program allows customers the opportunity to participate based on the needs and characteristics of their individual homes. A referral channel provides free, trusted referrals to customers seeking reliable, qualified contractors for their energy saving home improvement needs.

This program previously offered HVAC Audits and Room AC's, however, those measures were removed due to no longer being cost-effective.

The tables below show actual program performance for all current and past program measures.

RESIDENTIAL SERVICE – SMART \$AVER				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	201,592	81,238	43,398	2,898

## NON-RESIDENTIAL EE PROGRAMS

**Non-Residential Smart \$aver Energy Efficient Products and Assessment Program** (formerly known as the Energy Efficiency for Business Program)

The Non-Residential Smart \$aver Energy Efficient Products and Assessment Program provides incentives to DEP commercial and industrial customers to install high efficiency equipment in applications involving new construction and retrofits and to replace failed equipment.

Commercial and industrial customers can have significant energy consumption but may lack knowledge and understanding of the benefits of high efficiency alternatives. The Program provides financial incentives to help reduce the cost differential between standard and high efficiency equipment, offer a quicker return on investment, save money on customers' utility bills that can be reinvested in their business, and foster a cleaner environment. In addition, the Program encourages dealers and distributors (or market providers) to stock and provide these high efficiency alternatives to meet increased demand for the products.

The program provides incentives through prescriptive measures, custom measures and technical assistance.

- **Prescriptive Measures:** Customers receive incentive payments after the installation of certain high efficiency equipment found on the list of pre-defined prescriptive measures, including lighting; heating, ventilating and air conditioning equipment; and refrigeration measures and equipment. The program will no longer offer A-Line bulb incentives after 2020.
- **Custom Measures:** Custom measures are designed for customers with electrical energy saving projects involving more complicated or alternative technologies, whole-building projects, or those measures not included in the Prescriptive measure list. The intent of the Program is to encourage



the implementation of energy efficiency projects that would not otherwise be completed without the Company's technical or financial assistance. Unlike the Prescriptive portion of the program, all Custom measure incentives require pre-approval prior to the project implementation. The program will no longer offer A-Line bulb incentives after 2020.

- ***Energy Assessments and Design Assistance:*** Incentives are available to assist customers with energy studies such as energy audits, retro commissioning, and system-specific energy audits for existing buildings and with design assistance such as energy modeling for new construction. Customers may use a contracted Duke Energy vendor to perform the work or they may select their own vendor. Additionally, the Program assists customers who identify measures that may qualify for Smart \$aver Incentives with their applications. Pre-approval is required. In 2019, the program modified its approach to a Virtual Energy Assessment utilizing an energy modeling software to complete the assessment in 2-3 weeks at a lower cost.

NON-RESIDENTIAL SMART SAVER ENERGY EFFICIENCY PRODUCTS AND ASSESSMENT				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	76,167,085	759,203	137,149	49,442

\* NOTE: Participants have different units of measure.

## NON-RESIDENTIAL SMART \$AVER PERFORMANCE INCENTIVE PROGRAM

The Non-Residential Smart \$aver® Performance Incentive Program offers financial assistance to qualifying commercial, industrial and institutional customers to enhance their ability to adopt and install cost-effective electrical energy efficiency projects. The Program encourages the installation of new high efficiency equipment in new and existing nonresidential establishments as well as efficiency-related repair activities designed to maintain or enhance efficiency levels in currently installed equipment. Incentive payments are provided to offset a portion of the higher cost of energy efficient installations that are not eligible under the Smart \$aver® EE Products and Assessment program. The Program requires pre-approval prior to project initiation.

The types of projects covered by the Program include projects with some combination of unknown building conditions or system constraints, or uncertain operating, occupancy, or production schedules.

The intent of the Program is to broaden participation in non-residential efficiency programs by being able to provide incentives for projects that previously were deemed too unpredictable to calculate an acceptably accurate savings amount, and therefore ineligible for incentives. This Program provides a platform to understand new technologies better. Only projects that demonstrate that they clearly reduce electrical consumption and/or demand are eligible for incentives.

The key difference between this program and the custom component of the Non-Residential Smart \$aver Energy® Efficient Products and Assessment program is that Performance Incentive participants get paid based on actual measure performance, and involves the following two step process.

- ***Incentive #1:*** For the portion of savings that are expected to be achieved with a high degree of confidence, an initial incentive is paid once the installation is complete.
- ***Incentive #2:*** After actual performance is measured and verified, the performance-based part of the incentive is paid. The amount of the payout is tied directly to the savings achieved by the measures.

NON-RESIDENTIAL SMART \$AVER PERFORMANCE INCENTIVE				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	100	3,871	325	347

## SMALL BUSINESS ENERGY SAVER PROGRAM

The Small Business Energy Saver Program reduces energy usage through the direct installation of energy efficiency measures within qualifying non-residential customer facilities. Program measures address major end-uses in lighting, refrigeration, and HVAC applications. The program is available to existing non-residential customers that are not opted-out of the Company's EE/DSM Rider and have an average annual demand of 180 kW or less per active account.

Program participants receive a free, no-obligation energy assessment of their facility followed by a recommendation of energy efficiency measures to be installed in their facility along with the projected energy savings, costs of all materials and installation, and up-front incentive amount from Duke Energy Progress. The customer makes the final determination of which measures will be installed after receiving the results of the energy assessment. The Company-authorized vendor schedules the installation of the energy efficiency measures at a convenient time for the customer, and electrical subcontractors perform the work.

SMALL BUSINESS ENERGY SAVER				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	198,207,936	266,094	49,099	17,322

NOTE: Participants have different units of measure.

## COMBINED RESIDENTIAL/NON-RESIDENTIAL CUSTOMER

### ENERGY EFFICIENT LIGHTING PROGRAM

The Energy Efficient Lighting Program partners with lighting manufacturers and retailers across North and South Carolina to provide marked-down prices at the register to DEP customers purchasing energy efficient lighting products. Starting in 2017, the Program removed CFLs and only offers LEDs and energy-efficient fixtures.

As the program enters its eighth year, the DEP Energy Efficient Lighting Program will continue to encourage customers to adopt energy efficient lighting through incentives on a wide range of energy efficient lighting products. Customer education is imperative to ensure customers are purchasing the right bulb for the application in order to obtain high satisfaction with lighting products and subsequent purchases.

ENERGY EFFICIENT LIGHTING				
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)		
		MWH ENERGY	PEAK SKW	PEAK WKW
December 31, 2019	34,575,395	1,798,852	285,602	18,845

### DISTRIBUTION SYSTEM DEMAND RESPONSE PROGRAM (DSDR)

Duke Energy Progress' Distribution System Demand Response (DSDR) program manages the application and operation of voltage regulators (the Volt) and capacitors (the VAR) on the Duke Energy Progress distribution system. In general, the program tends to optimize the operation of these devices, resulting in a "flattening" of the voltage profile across an entire circuit, starting at the substation and continuing out to the farthest endpoint on that circuit. This flattening of the voltage profile is accomplished by automating the substation level voltage regulation and capacitors, line capacitors and line voltage regulators while integrating them into a single control system. This control system continuously monitors and operates the voltage regulators and capacitors to maintain the desired "flat" voltage profile. Once the system is operating with a relatively flat voltage profile across an entire circuit, the resulting circuit voltage at the substation can then be operated at a lower overall level. Lowering the circuit voltage at the substation, results in an immediate reduction of system loading during peak conditions.

DISTRIBUTION SYSTEM DEMAND RESPONSE			
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	GROSS SAVINGS (AT PLANT)	
		MWH ENERGY	SUMMER MW CAPABILITY
December 31, 2019	N/A	38,084	251

Since DEP's last biennial resource plan was filed on September 1, 2018, there have been 25 voltage control activations through July 30, 2020. The following table shows the date, starting and ending time, and duration for all voltage control activations from July 2018 through July 2020.

VOLTAGE CONTROL ACTIVATIONS			
DATE	START TIME	END TIME	DURATION (H:MM)
10/8/2018	9:27	9:41	0:14
11/21/2018	12:55	13:06	0:11
11/28/2018	6:30	9:30	3:00
11/29/2018	6:00	10:00	4:00
1/17/2019	9:16	9:25	0:09
1/21/2019	6:00	9:12	3:12
1/22/2019	6:00	9:40	3:40
1/31/2019	6:00	9:30	3:30
3/6/2019	6:00	8:00	2:00
3/7/2019	6:00	9:00	3:00
4/1/2019	6:00	8:30	2:30
4/3/2019	6:00	10:00	4:00
4/21/2019	11:08	11:48	0:40
4/24/2019	18:00	21:30	3:30
4/25/2019	18:30	21:30	3:00
8/11/2019	8:44	8:58	0:14
8/13/2019	16:00	16:52	0:52
8/14/2019	16:00	19:00	3:00
10/2/2019	16:00	20:00	4:00
10/3/2019	16:00	20:00	4:00
11/13/2019	6:00	9:30	3:30
11/14/2019	6:00	9:30	3:30
6/4/2020	18:00	20:30	2:30

VOLTAGE CONTROL ACTIVATIONS			
DATE	START TIME	END TIME	DURATION (H:MM)
7/16/2020	18:05	21:00	2:55
7/30/2020	18:00	21:00	3:00

## DEMAND-SIDE MANAGEMENT PROGRAMS

### RESIDENTIAL:

#### ENERGYWISE<sup>SM</sup> HOME PROGRAM

The EnergyWise<sup>SM</sup> Home Program allows DEP to install load control switches at the customer's premise to remotely control the following residential appliances:

- Central air conditioning or electric heat pumps
- Auxiliary strip heat on central electric heat pumps (Western Region only)
- Electric water heaters (Western Region only).

For each of the appliance options above, an initial one-time bill credit of \$25 following the successful installation and testing of load control device(s) and an annual bill credit of \$25 is provided to program participants in exchange for allowing the Company to control the listed appliances.

ENERGYWISE <sup>SM</sup> HOME			
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS*	2019 CAPABILITY (MW@GEN)	
		SUMMER	WINTER
December 31, 2019	196,192	405	14.1

\* Number of participants represents the number of measures under control.

The following table shows Residential EnergyWise<sup>SM</sup> Home Program activations that were for the general population from July 1, 2018 through December 31, 2019.

ENERGYWISE <sup>SM</sup> HOME PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION
11/28/2018	6:30 am	9:00 am	150	11.7
11/29/2018	6:30 am	9:00 am	150	10.9
1/31/2019	6:30 am	9:00 am	150	13
7/2/2019	4:30 pm	5:00 pm	30	311
7/17/2019	3:30 pm	6:00 pm	150	173
11/13/2019	6:00 am	9:30 am	150	6

**EnergyWise<sup>SM</sup> Home** added a summer cooling Bring Your Own Thermostat (BYOT) option in late December 2019. Customer acquisition for this program option year to date through June 2020 is 6,800 participants. No activations of this program option have been administered through June 2020.

## NON-RESIDENTIAL

### DEMAND RESPONSE – CURTAILABLE PROGRAMS AND RELATED RATE STRUCTURES

The DEP non-residential demand response portfolio consists of a combination of programs that rely either on the customer’s ability to respond to a utility-initiated notification or on receipt of a signal to control customer equipment, including small business thermostats. Customers are offered ongoing incentives commensurate to the amount of load they are capable of curtailing.

The recent Nexant Market Potential Study forecasted minimal summer and winter non-residential DSM growth opportunities in the Carolinas, particularly for the small and medium business segment. Further, given the impact of the Enhanced scenario’s doubling of incentives on program cost-effectiveness and future DSM rate adjustments, the Base scenario would be considered more applicable for the large non-residential segment. The large business demand response programs are actively marketed to all customer segments that are known to possess the flexibility to curtail load and have demands high enough to comply with program minimums, which means that there is a simultaneous effort to maximize both winter and summer resources. Although they provide for flexibility in contracting for different winter and summer commitments due to seasonal variations in customers’ loads and operational characteristics, the programs are designed to incent participants to provide curtailable demand year-round. This allows for



availability of the programs even in off-peak months when scheduled generation maintenance, in conjunction with unseasonable temperatures or other weather events, could lead to the need for demand-side management resources.

Duke Energy Progress' current curtailable programs include:

## COMMERCIAL, INDUSTRIAL, AND GOVERNMENTAL (CIG) DEMAND RESPONSE AUTOMATION PROGRAM

The CIG Demand Response Automation Program allows DEP to install load control and data acquisition devices to remotely control and monitor a wide variety of electrical equipment capable of serving as a demand response resource. The goal of this program is to utilize customer education, enabling two-way communication technologies, and an event-based incentive structure to maximize load reduction capabilities and resource reliability. The primary objective of this program is to reduce DEP's need for additional peaking generation. This is accomplished by reducing DEP's seasonal peak load demands through deployment of load control and data acquisition technologies.

CIG DEMAND RESPONSE AUTOMATION STATISTICS			
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MW CAPABILITY	
		SUMMER	WINTER
December 31, 2019	85	22.6	12.1

The table below shows information for each CIG Demand Response Automation Program non-test control event from January 1, 2018 through December 31, 2019.

CIG DEMAND RESPONSE AUTOMATION PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION
1/2/2018	7:00 am	10:00 am	180	7.5
1/7/2018	6:00 am	11:00 am	300	8.7
1/15/2018	5:00 am	10:00 am	300	8.1
1/18/2018	5:30 am	9:30 am	240	7.1
6/19/2018	1:00 pm	7:00 pm	360	22.2
8/8/2018	1:00 pm	7:00 pm	360	21.7
8/28/2018	1:00 pm	7:00 pm	360	20.7
7/2/2019	1:00 pm	7:00 pm	360	27.1
7/17/2019	1:00 pm	7:00 pm	360	25.7
8/14/2019	1:00 pm	7:00 pm	360	25.8

**Large Load Curtailable Rates & Riders:** Participants agree contractually to reduce their electrical loads to specified levels upon request by DEP. If customers fail to do so during an interruption, they receive a penalty for the increment of demand exceeding the specified level.

LARGE LOAD CURTAILABLE STATISTICS			
CUMULATIVE AS OF:	NUMBER OF PARTICIPANTS	MW CAPABILITY	
		SUMMER	WINTER
December 31, 2019	58	283	255

LARGE LOAD CURTAILABLE PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION
1/2/2018	6:30 am	10:00 am	210	262
1/7/2018	6:00 am	11:00 am	300	201
1/15/2018	5:00 am	10:00 am	300	262
1/18/2018	5:30 am	9:30 am	240	262

## ENERGYWISE® BUSINESS PROGRAM

EnergyWise® Business is both an energy efficiency and demand response program for non-residential customers that allows DEP to reduce the operation of participants' air conditioning units to mitigate system capacity constraints and improve reliability of the power grid.

Program participants can choose between a Wi-Fi thermostat or load control switch that will be professionally installed for free on each air conditioning or heat pump unit. In addition to equipment choice, participants can also select the cycling level they prefer (i.e., a 30%, 50% or 75% reduction of the normal on/off cycle of the unit). During a conservation period, DEP will send a signal to the thermostat or switch to reduce the on time of the unit by the cycling percentage selected by the participant. Participating customers will receive a \$50 annual bill credit for each unit at the 30% cycling level, \$85 for 50% cycling, or \$135 for 75% cycling. Participants that have a heat pump unit with electric resistance emergency/back up heat and choose the thermostat can also participate in a winter option that allows control of the emergency/back up heat at 100% cycling for an additional \$25 annual bill credit. Participants will also be allowed to override two conservation periods per year.

Participants choosing the thermostat will be given access to a portal that will allow them to set schedules, adjust the temperature set points, and receive energy conservation tips and communications from DEP anywhere they have internet access. In addition to the portal access, participants will also receive conservation period notifications, so they can make adjustments to their schedules or notify their employees of upcoming conservation periods.

ENERGYWISE® BUSINESS				
CUMULATIVE AS OF:	PARTICIPANTS*	MW CAPABILITY		MWH ENERGY SAVINGS (AT PLANT)
		SUMMER	WINTER	
December 31, 2019	6,403	5.4	0.6	12.6

\* Number of participants represents the number of measures under control.

The following table shows EnergyWise® Business program activations that were not for testing purposes from January 1, 2018 through December 31, 2019.

ENERGYWISE® BUSINESS PROGRAM ACTIVATIONS				
DATE	START TIME	END TIME	DURATION (MINUTES)	MW LOAD REDUCTION
8/28/2018	4:00 pm	6:00 pm	120	2.8
7/2/2019	4:00 pm	6:00 pm	120	4.4
7/17/2019	4:00 pm	6:00 pm	120	4.5

## DISCONTINUED DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS

Since the last biennial Resource Plan filing, no DEP DSM/EE programs have been discontinued.

### DSM/EE PROGRAMS PRIOR TO NC SENATE BILL 3

Prior to the passage of North Carolina Senate Bill 3 in 2007, DEP had a number of DSM/EE programs in place. These programs are available in both North and South Carolina and include the following:

#### ENERGY EFFICIENT HOME PROGRAM

##### PROGRAM TYPE: ENERGY EFFICIENCY

In the early 1980s, DEP introduced an Energy Efficient Home program that provides residential customers with a 5% discount of the energy and demand portions of their electricity bills when their homes met certain thermal efficiency standards that were significantly above the existing building

codes and standards. Homes that pass an ENERGY STAR® test receive a certificate as well as a 5% discount on the energy and demand portions of their electricity bills.

## **CURTAILABLE RATES**

### **PROGRAM TYPE: DEMAND RESPONSE**

DEP began offering its curtailable rate options in the late 1970s, whereby industrial and commercial customers receive credits for DEP's ability to curtail system load during times of high energy costs and/or capacity constrained periods. There were no curtailable rate activations during the period from July 1, 2016 through December 31, 2017.

## **TIME-OF-USE RATES**

### **PROGRAM TYPE: DEMAND RESPONSE**

DEP has offered voluntary Time-of-Use (TOU) rates to all customers since 1981. These rates provide incentives to customers to shift consumption of electricity to lower-cost off-peak periods and lower their electric bill.

## **THERMAL ENERGY STORAGE RATES**

### **PROGRAM TYPE: DEMAND RESPONSE**

DEP began offering thermal energy storage rates in 1979. The present General Service (Thermal Energy Storage) rate schedule uses two-period pricing with seasonal demand and energy rates applicable to thermal storage space conditioning equipment. Summer on-peak hours are noon to 8 p.m. and non-summer hours of 6 a.m. to 1 p.m. weekdays.

## **REAL-TIME PRICING**

### **PROGRAM TYPE: DEMAND RESPONSE**

DEP's Large General Service (Experimental) Real Time Pricing tariff was implemented in 1998. This tariff uses a two-part real-time pricing rate design with baseline load representative of historic usage.

Hourly rates are provided on the prior business day. A minimum of 1 MW load is required. This rate schedule is presently fully subscribed.

The following table provides current information available at the time of this report on DEP's pre-Senate Bill 3 DSM/EE programs (i.e., those programs that were in effect prior to January 1, 2008). This information, where applicable, includes program type, capacity, energy, and number of customers enrolled in the program as of the end of 2019, as well as load control activations since those enumerated in DEP's last biennial resource plan. The energy savings impacts of these existing programs are embedded within DEP's load and energy forecasts.

PROGRAM DESCRIPTION	TYPE	SUMMER CAPACITY (MW)	WINTER CAPACITY (MW)	ANNUAL ENERGY (MWH)	PARTICIPANTS	ACTIVATIONS SINCE LAST BIENNIAL REPORT
Energy Efficiency Programs <sup>2</sup>	EE	458	N/A	N/A	N/A	N/A
Real Time Pricing (RTP)	DSM	29.8	49.7	N/A	99	N/A
Commercial & Industrial TOU	DSM	12.0	12.0	N/A	33,791	N/A
Residential TOU	DSM	5.2	5.2	N/A	23,587	N/A
Curtailable Rates	DSM	284	255	N/A	58	4

## FUTURE EE AND DSM PROGRAMS

DEP is continually seeking to enhance its DSM/EE portfolio by: (1) adding new or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new measurement and verification (M&V) results, and (3) other EE pilots.

DEP plans to evaluate and consider the addition/expansion of cost-effective winter measures to the **EnergyWise<sup>SM</sup> Home** program in 2020. These measures include addition of winter BYOT, and expanding water heating control, and heat pump heat strip control to the rest of the system territory (beyond DEP West).

<sup>2</sup> Impacts from these existing programs are embedded within the load and energy forecast.

Potential new programs and/or measures will be reviewed with the DSM Collaborative then submitted to the Public Utility Commissions as required for approval.

## EE AND DSM PROGRAM SCREENING

The Company evaluates the costs and benefits of DSM and EE programs and measures by using the same data for both generation planning and DSM/EE program planning to ensure that demand-side resources are compared to supply side resources on a level playing field.

The analysis of energy efficiency and demand-side management cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test, Rate Impact Measure Test, Total Resource Cost Test, and Participant Test (PCT).

- The UCT compares utility benefits (avoided costs) to the costs incurred by the utility to implement the program, and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.
- The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.
- The TRC Test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test, however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC.



- The Participant Test evaluates programs from the perspective of the program's participants. The benefits include reductions in utility bills, incentives paid by the utility and any State, Federal or local tax benefits received.

The use of multiple tests can ensure the development of a reasonable set of cost-effective DSM and EE programs and indicate the likelihood that customers will participate.

## ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT PROGRAM FORECASTS

### FORECAST METHODOLOGY

In 2019, DEP commissioned a new EE market potential study to obtain new estimates of the technical, economic and achievable potential for EE savings within the DEP service area. The final reports (one for South Carolina and one for North Carolina) were prepared by Nexant Inc. and issued in May 2020 with a final revision completed in June 2020.

The Nexant study results are suitable for IRP purposes and for use in long-range system planning models. This study also helps to inform utility program planners regarding the extent of EE opportunities and to provide broadly defined approaches for acquiring savings. This study did not, however, attempt to closely forecast EE achievements in the short-term or from year to year. Such an annual accounting is highly sensitive to the nature of programs adopted as well as the timing of the introduction of those programs. As a result, it was not designed to provide detailed specifications and work plans required for program implementation. The study provides part of the picture for planning EE programs. Fully implementable EE program plans are best developed considering this study along with the experience gained from currently running programs, input from DEP program managers and EE planners, feedback from the DSM Collaborative and with the possible assistance of implementation contractors.

The Nexant market potential study (MPS) included projections of Energy Efficiency impacts over a 25-year period for a Base, Enhanced and Avoided Energy Cost Sensitivity Scenario, which were used in conjunction with expected EE savings from DEP's five-year program plan to develop the Base, High and Low Case EE savings forecasts for this IRP.

The Base Case EE savings forecast represents a merging of the projected near-term savings from DEP's five-year plan (2020-2024) with the long-term savings from the Nexant MPS (2030-onward). Savings

during the five-year period (2025-2029) between the two sets of projections represents a merging of the two forecasts to ensure a smooth transition.

The High Case EE savings forecast was developed using the same process as the Base case, however; for the Nexant MPS portion of the forecast, the difference between the Avoided Energy Cost Sensitivity and Base Scenarios for all years was added to the Enhanced Case forecast. This method captures the higher EE savings resulting from both the higher avoided energy cost assumptions as well as from increased customer incentives in the Enhanced case.

Finally, the Low Case was developed by applying a reduction factor to the Base Case forecast. Additionally, the cumulative savings projections for the Base, High and Low Case EE forecasts included an assumption that when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with these measures are removed from the future projected EE impacts, a process defined as “rolloff”.

The tables below provide the projected MWh load impacts for the Base, High and Low Case forecasts of all DEP EE programs implemented since 2008 on a Net of Free Riders basis. The Company assumes total EE savings will continue to grow on an annual basis throughout the planning, however, the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan. Please note that this table includes a column that shows historical EE program savings since the inception of the EE programs in 2008 through the end of 2019, which accounts for approximately an additional 2,600 gigawatt-hours (GWh) of net energy savings.

The following forecast is presented without the effects of “rolloff”:

## PROJECTED MWH IMPACTS OF EE PROGRAMS BASE CASE

YEAR	ANNUAL MWH LOAD REDUCTION - NET	
	INCLUDING MEASURES ADDED IN 2020 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2008
2008-19		2,603,928
2020	382,403	2,986,331
2021	594,043	3,197,971
2022	797,571	3,401,499
2023	993,570	3,597,498
2024	1,181,566	3,785,494
2025	1,366,448	3,970,376
2026	1,529,702	4,133,630
2027	1,671,328	4,275,256
2028	1,791,325	4,395,253
2029	1,889,695	4,493,623
2030	1,966,436	4,570,364
2031	2,025,870	4,629,798
2032	2,083,615	4,687,543
2033	2,139,751	4,743,679
2034	2,194,754	4,798,682
2035	2,248,708	4,852,636

*\*The MWh totals included in the table above represent the annual year-end impacts associated with EE programs, however, the MWh totals included in the load forecast portion of this document represent the sum of the expected hourly impacts.*

## PROJECTED MWH IMPACTS OF EE PROGRAMS HIGH CASE

YEAR	ANNUAL MWH LOAD REDUCTION - NET	
	INCLUDING MEASURES ADDED IN 2020 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2008
2008-19		2,603,928
2020	382,403	2,986,331
2021	615,166	3,219,094
2022	839,006	3,442,934
2023	1,054,565	3,658,493
2024	1,261,319	3,865,247
2025	1,464,574	4,068,502
2026	1,645,430	4,249,358
2027	1,803,887	4,407,815
2028	1,939,945	4,543,873
2029	2,053,605	4,657,533
2030	2,144,866	4,748,794
2031	2,217,588	4,821,516
2032	2,287,784	4,891,712
2033	2,355,661	4,959,589
2034	2,421,746	5,025,674
2035	2,486,249	5,090,177

*\*The MWh totals included in the table above represent the annual year-end impacts associated with EE programs, however, the MWh totals included in the load forecast portion of this document represent the sum of the expected hourly impacts.*

## PROJECTED MWH IMPACTS OF EE PROGRAMS LOW CASE

YEAR	ANNUAL MWH LOAD REDUCTION - NET	
	INCLUDING MEASURES ADDED IN 2020 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2008
2008-19		2,603,928
2020	286,802	2,890,730
2021	445,532	3,049,460
2022	598,178	3,202,106
2023	745,178	3,349,106
2024	886,174	3,490,102
2025	1,024,836	3,628,764
2026	1,147,276	3,751,204
2027	1,253,496	3,857,424
2028	1,343,494	3,947,422
2029	1,417,271	4,021,199
2030	1,474,827	4,078,755
2031	1,519,403	4,123,331
2032	1,562,711	4,166,639
2033	1,604,813	4,208,741
2034	1,646,066	4,249,994
2035	1,686,531	4,290,459

*\*The MWh totals included in the table above represent the annual year-end impacts associated with EE programs, however, the MWh totals included in the load forecast portion of this document represent the sum of the expected hourly impacts.*

The MW impacts from the EE programs are included in the Load Forecasting section of this IRP. The table below provides the projected summer and winter peak MW load impacts of all current and projected DEP DSM programs.

### Projected MW Load Impacts of DSM Programs

YEAR	SUMMER PEAK MW REDUCTION					
	ENERGYWISE HOME	CIG DEMAND RESPONSE	DSDR	LARGE LOAD CURTAILABLE	ENERGYWISE FOR BUSINESS	TOTAL SUMMER PEAK
2020	408	28	226	283	13	958
2021	419	31	227	286	16	979
2022	420	35	226	289	19	989
2023	420	39	229	292	22	1002
2024	421	43	230	295	22	1010
2025	421	45	231	298	22	1017
2026	422	45	233	299	22	1021
2027	424	45	235	299	22	1024
2028	425	45	237	299	22	1028
2029	428	45	239	299	22	1032
2030	431	45	240	299	22	1037
2031	434	45	244	299	22	1044
2032	437	45	247	299	22	1050
2033	441	45	248	299	22	1055
2034	443	45	251	299	22	1061
2035	446	45	254	299	22	1065

NOTE: For DSM programs, Gross and Net are the same.

### Projected MW Load Impacts of DSM Programs

YEAR	WINTER PEAK MW REDUCTION					
	ENERGYWISE HOME	CIG DEMAND RESPONSE	DSDR	LARGE LOAD CURTAILABLE	ENERGYWISE FOR BUSINESS	TOTAL WINTER PEAK
2020	15	15	215	253	1	499
2021	20	16	216	255	1	509
2022	26	18	215	258	2	519
2023	30	21	218	260	2	531
2024	33	23	219	263	2	539
2025	36	25	220	266	2	549
2026	41	25	222	268	2	558
2027	48	25	223	268	2	567
2028	58	25	225	268	2	579
2029	72	25	227	268	2	594
2030	89	25	229	268	2	613
2031	109	25	232	268	2	636
2032	130	25	235	268	2	660
2033	152	25	236	268	2	683
2034	172	25	239	268	2	706
2035	189	25	242	268	2	725

NOTE: For DSM programs, Gross and Net are the same.

Pursuing EE and DSM initiatives is not expected to meet the growing demand for electricity. DEP still envisions the need to secure additional generation, as well as cost-effective renewable generation, but the EE and DSM programs offered by DEP will address a significant portion of this need if such programs perform as expected.

### PROGRAMS EVALUATED BUT REJECTED

Duke Energy Progress has not rejected any cost-effective programs as a result of its EE and DSM program screening.

### CURRENT AND ANTICIPATED CONSUMER EDUCATION PROGRAMS



In addition to the DSM/EE programs previously listed, DEP also has the following informational and educational programs.

- On Line Account Access
- “Lower My Bill” Toolkit
- Online Energy Saving Tips
- Energy Resource Center
- Large Account Management
- Business Energy Advisors/ Web page
- Community Events
- Energy Efficiency Engineers
- Virtual Energy Assessments
- New Construction Energy Efficiency Design Assistance
- Newsletters

## ON LINE ACCOUNT ACCESS

On Line Account Access provides energy analysis tools to assist customers in gaining a better understanding of their energy usage patterns and identifying opportunities to reduce energy consumption. The service allows customers to view their past 24 months of electric usage including the date the bill was mailed; number of days in the billing cycle; and daily temperature information. This program was initiated in 1999.

## “LOWER MY BILL” TOOLKIT

This tool, implemented in 2004, provides on-line tips and specific steps to help customers reduce energy consumption and lower their utility bills. These range from relatively simple no-cost steps to more extensive actions involving insulation and heating and cooling equipment.

## ONLINE ENERGY SAVING TIPS

DEP has been providing tips on how to reduce home energy costs since approximately 1981. DEP's web site includes information on household energy wasters and how a few simple actions can increase efficiency.

## **ENERGY RESOURCE CENTER**

In 2000, DEP began offering its large commercial, industrial, and governmental customers a wide array of tools and resources to use in managing their energy usage and reducing their electrical demand and overall energy costs. Through its Energy Resource Center, located on the DEP web site, DEP provides newsletters, online tools and information which cover a variety of energy efficiency topics such as electric chiller operation, lighting system efficiency, compressed air systems, motor management, variable speed drives and energy audits.

## **LARGE ACCOUNT MANAGEMENT**

All DEP commercial, industrial, and governmental customers with an annual electric bill greater than \$250,000 are assigned to a DEP Account Executive (AE). The AEs are available to personally assist customers in evaluating energy improvement opportunities and can bring in other internal resources to provide detailed analyses of energy system upgrades. The AEs provide their customers with a monthly electronic newsletter, which includes energy efficiency topics and tips. They also offer numerous educational opportunities in group settings to provide information about DEP's new DSM and EE program offerings and to help ensure the customers are aware of the latest energy improvement and system operational techniques.

## **BUSINESS ENERGY ADVISORS/ WEB PAGE**

Business Energy Advisors (BEA's) provide guidance for commercial and industrial energy needs. They implement a holistic approach to solving customer's energy problems. The approach includes developing and leveraging customer relationships to deliver high quality solutions to SMB customers through a portfolio of products and services that drive customer engagement and loyalty. BEA's portfolio focus primarily on customers with \$60,000-\$250,000 annual electricity spend. In addition, BEA's assist Large Account Managers (LAM) with EE solutions as well as leads and inquiries coming from other departments including the Customer Call Center.

## COMMUNITY EVENTS

DEP representatives participated in community events across the service territory to educate customers about DEP's energy efficiency programs and rebates and to share practical energy saving tips. DEP energy experts attended conference events and forums to host informational tables and displays, and distributed handout materials directly encouraging customers to learn more about and sign up for approved DSM/EE energy saving programs.

## ENERGY EFFICIENCY ENGINEERS

Energy Efficiency Engineers (EEE) are available to work with Duke Energy's non-residential sector largest customers to review, evaluate, and provide guidance with customer energy efficiency projects. The EEE has the energy efficiency knowledge to interact with customers, customer engineers and vendors. EEEs also educate customers on program requirements and processes, the identification of potential projects, the evaluation of data and measures, and the calculations required for the identified projects.

## VIRTUAL ENERGY ASSESSMENTS

A building is the face of any organization and it makes an important impression. A virtual assessment is an ideal service for medium and large facilities to take control of their energy consumption – driving down operational costs, increasing efficiency, meeting sustainability goals and addressing aging infrastructure. Using state-of-the-art software, DEP's innovative approach to energy assessments will jump-start you toward your goals. Instead of taking months analyzing data, a virtual assessment can be completed in only a few weeks. Less engineering time and more technology free up resources that can be put toward projects that will save for years to come.

## NEW CONSTRUCTION ENERGY EFFICIENCY DESIGN ASSISTANCE

Duke Energy has a dedicated team ready to help businesses integrate energy saving systems into existing buildings and new construction. The DEP team will work with you and your staff to provide cost-effective, energy efficiency system design options that will reduce long-term operating costs. DEP will provide energy consulting services, whole building energy modeling, system design options for

you to choose from with estimated savings and cost/payback metrics, and then provide assistance with the Smart Saver Incentive Application process.

## NEWSLETTERS

Duke Energy uses Questline to send regular newsletters to small, medium, large businesses, and trade allies with current articles focused on the importance of energy efficiency. The newsletters offer tools and contacts to help in the Smart \$aver application process.

## DISCONTINUED CONSUMER EDUCATION PROGRAMS

DEP has not discontinued any consumer education programs since the last biennial Resource Plan filing.

## EE SAVINGS VARIANCE SINCE LAST IRP

In response to Order number 7 in the NCUC Order Approving Integrated Resource Plans and REPS Compliance Plans regarding the 2014 Biennial IRPs, the Base Portfolio EE savings forecast of MWh is within 10% of the forecast presented in the 2018 IRP when compared on the cumulative achievements at year 2035 of the forecasts as shown in the table below.

YEAR	2018 IRP		2020 IRP		% CHANGE FROM 2018 TO 2020 IRP
	ANNUAL MWH LOAD REDUCTION - NET		ANNUAL MWH LOAD REDUCTION - NET		
	INCLUDING MEASURES ADDED IN 2018 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2009	INCLUDING MEASURES ADDED IN 2020 AND BEYOND	INCLUDING MEASURES ADDED SINCE 2009	
2018	230,996	2,347,887			
2019	422,130	2,539,021		2,603,928	2.6%
2020	605,468	2,722,359	382,403	2,986,331	9.7%
2021	777,345	2,894,236	594,043	3,197,971	10.5%
2022	945,787	3,062,678	797,571	3,401,499	11.1%
2023	1,114,230	3,231,121	993,570	3,597,498	11.3%
2024	1,282,674	3,399,565	1,181,566	3,785,494	11.4%
2025	1,451,119	3,568,010	1,366,448	3,970,376	11.3%
2026	1,619,565	3,736,456	1,529,702	4,133,630	10.6%
2027	1,788,012	3,904,903	1,671,328	4,275,256	9.5%
2028	1,956,460	4,073,351	1,791,325	4,395,253	7.9%
2029	2,125,763	4,242,654	1,889,695	4,493,623	5.9%
2030	2,295,309	4,412,200	1,966,436	4,570,364	3.6%
2031	2,466,556	4,583,447	2,025,870	4,629,798	1.0%
2032	2,639,409	4,756,300	2,083,615	4,687,543	-1.4%
2033	2,812,935	4,929,826	2,139,751	4,743,679	-3.8%
2034	2,988,465	5,105,356	2,194,754	4,798,682	-6.0%
2035	3,166,853	5,283,744	2,248,708	4,852,636	-8.2%

Base Case Comparison to 2018 DEP IRP

## INTEGRATED VOLT-VAR CONTROL

### PROGRAM DESCRIPTION

Distribution System Demand Response (DSDR) is an operational mode of Volt Var Optimization (VVO) that supports peak shaving and emergency MW (demand) reduction. Duke Energy Progress (DEP) implemented DSDR in 2014. The DSDR mode of operation is implemented by the software within a centralized Distribution Management System (DMS). The DMS obtains telemetered data via 2-way communications from substation devices, distribution line voltage regulators, distribution line capacitor banks, medium voltage sensors, and low voltage sensors. The DMS software performs a power load flow analysis based on near real-time measurement inputs. Afterwards, it sends out commands to the voltage regulators and capacitor banks to optimize the voltage for DSDR. Currently, DSDR can provide peak shaving voltage reduction of approximately 3.6% across the distribution network in DEP. The DMS in

DEP is capable of optimized modes (i.e.- DSDR) or non-optimized (i.e. – emergency) modes. The emergency modes are designed for a speedy, temporary response during bulk power emergencies with voltage reduction capability of up to 5.0%. Initially, the DEP DSDR targeted approximately 310 MW of peak demand reduction capability to defer construction of a new Combustion Turbine (CT) plant. The North Carolina Utility Commission classified DSDR as an Energy Efficiency program with rider recovery. The goal was exceeded and DEP achieved 322 MW of load reduction.

The initial implementation of DSDR not only included a Distribution Management System (DMS), but also a significant amount of circuit conditioning (such as installing voltage regulating devices and capacitors, balancing load on distribution circuits, and reconductoring some distribution lines to larger wire sizes). These forms of circuit conditioning help reduce line losses, which improve grid efficiency, reduce reactive power on the grid, and enable a higher voltage reduction to achieve maximum peak shaving. Additional devices, such as medium voltage sensors and low voltage sensors, were deployed to provide additional telemetry on the system. The substation and distribution line devices needed for DSDR were deployed in the optimal locations and equipped with 2-way communications ability.

The purpose of this evaluation is to conduct a cost/benefit analysis of moving DEP from the current DSDR (peak shaving) operational strategy to a Conservation Voltage Reduction (CVR) operational strategy. Conservation Voltage Reduction (CVR) is an operational mode of VVO that supports voltage reduction and energy conservation. The CVR functionality would target an estimated 2% voltage reduction for the majority of the hours in the year. This voltage reduction is estimated to result in an approximate 1.4% load reduction on average for enabled circuits. The substation, distribution, telecommunications, and IT infrastructure are already in place because DSDR already exists in DEP. As such, it is expected that few new devices will be installed. The current DEP DMS will transition to the enterprise DMS platform in the future. The software within the future enterprise DMS platform will have the ability to operate in various modes, including the current DSDR mode and CVR mode. This evaluation assumes the future version of the DMS platform will have already been deployed with the software capability to operate in DSDR or CVR mode, and that comprehensive testing will have already been performed on the required changes to the DMS system. Because the 2-way communications and control infrastructure are already in place in DEP, the settings on the substation and distribution devices can be programmed to enable these devices to properly operate when the DMS is in CVR mode or DSDR mode.

Changing the predominant operational strategy in DEP from DSDR to CVR would affect the amount of maximum peak shaving capability. If the DMS is operating in CVR mode, transitioning to DSDR mode when load has already been reduced will not provide the peak shaving benefit realized today. The net

result is that the amount of peak shaving would be reduced, and therefore will require relief from the current DSDR peak shaving obligation. This evaluation shows the incremental cost/benefits of transitioning to CVR operational mode. However, the lost benefits (including the initial deferral of peaking units), due to the reduction of peak shaving capability have yet to be calculated. To make an informed decision, further analysis will be required to accurately quantify the impacts on DSDR. When the DMS upgrade is complete, Duke Energy will be able to conduct additional testing and a more thorough analysis of the peak shaving capability impact.

## **BENEFITS:**

- Reduced distribution line losses due to lower overall voltage
- More efficient grid due to lower line losses and reduced reactive power
- Less generation fuel consumed and lower emissions due to grid efficiencies
- Integrated control of capacitor banks provides greater ability to reduce reactive power, resulting in less apparent load on the system
- Less peak load on the grid could result in a reduced need to build additional peaking generation
- Optimized control of volt/VAR devices improves the grid's ability to respond to intermittency
- Helps to manage integration of distributed energy resources

IVVC is part of the proposed Duke Energy Carolinas Grid Improvement Plan. The deployment of an IVVC program for DEP is anticipated to take approximately four years. In the meantime, DSDR will continue to operate as planned as a peak shaving resource until it is fully rolled into IVVC in 2025.



SUMMARY DEP (NORTH CAROLINA & SOUTH CAROLINA) DISTRIBUTION SYSTEM DEMAND RESPONSE (DSDR) CONVERSION TO YEAR-ROUND CONSERVATION VOLTAGE REDUCTION (CVR) ANNUAL ESTIMATED ENERGY REDUCTION (KWH) OPERATING CONSERVATION VOLTAGE REDUCTION (CVR) 90% OF THE HOURS ON DISTRIBUTION RETAIL CIRCUITS*		
YEAR	DSDR TO CVR DEPLOYMENT (%)	TOTAL REDUCTION (KWH)*
2018	0%	0
2019	0%	0
2020	0%	0
2021	0%	0
2022	0%	0
2023	10%	8,639,128
2024	20%	17,433,760
2025	100%	87,953,319
2026	100%	88,744,899
2027	100%	89,543,603
2028	100%	90,349,495
2029	100%	91,162,641
2030	100%	91,983,105
2031	100%	92,810,953
2032	100%	93,646,251
2033	100%	94,489,067
2034	100%	95,339,469
2035	100%	96,197,524
2036	100%	97,063,302

\*(Energy reduction does not account for system losses upstream of distribution retail substations)

**DEP (NORTH CAROLINA & SOUTH CAROLINA)**  
**IVVC PEAK-SHAVING MODE APPROXIMATELY <10% OF HOURS PER YEAR (KW)\***

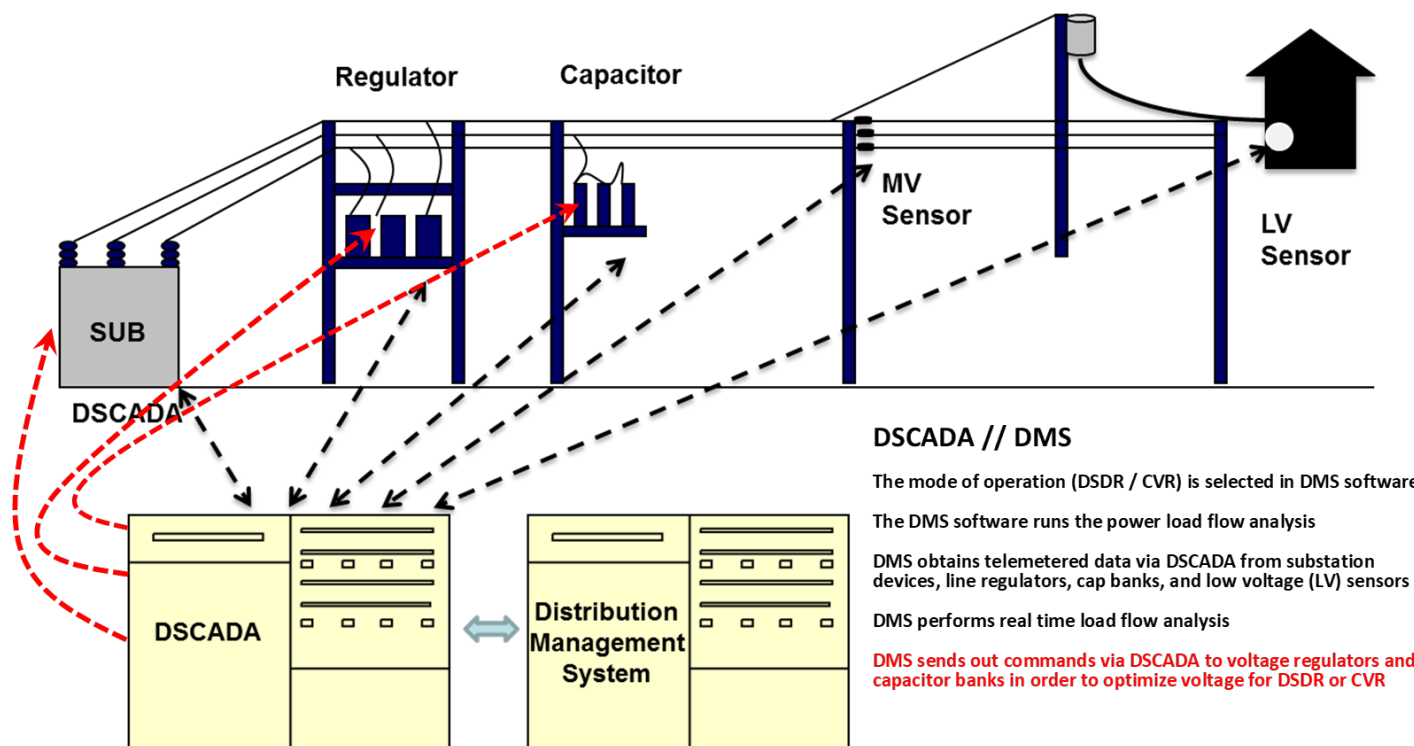
YEAR	IVVC DEPLOYMENT (%)	TOTAL REDUCTION (KW)*
2018	0%	0
2019	0%	0
2020	0%	0
2021	0%	0
2022	0%	0
2023	10%	9,432
2024	20%	19,035
2025	100%	96,030
2026	100%	96,895
2027	100%	97,767
2028	100%	98,647
2029	100%	99,534
2030	100%	100,430
2031	100%	101,334
2032	100%	102,246
2033	100%	103,166
2034	100%	104,095
2035	100%	105,032
2036	100%	105,977

\*(Demand reduction does not account for system losses upstream of distribution retail substations)

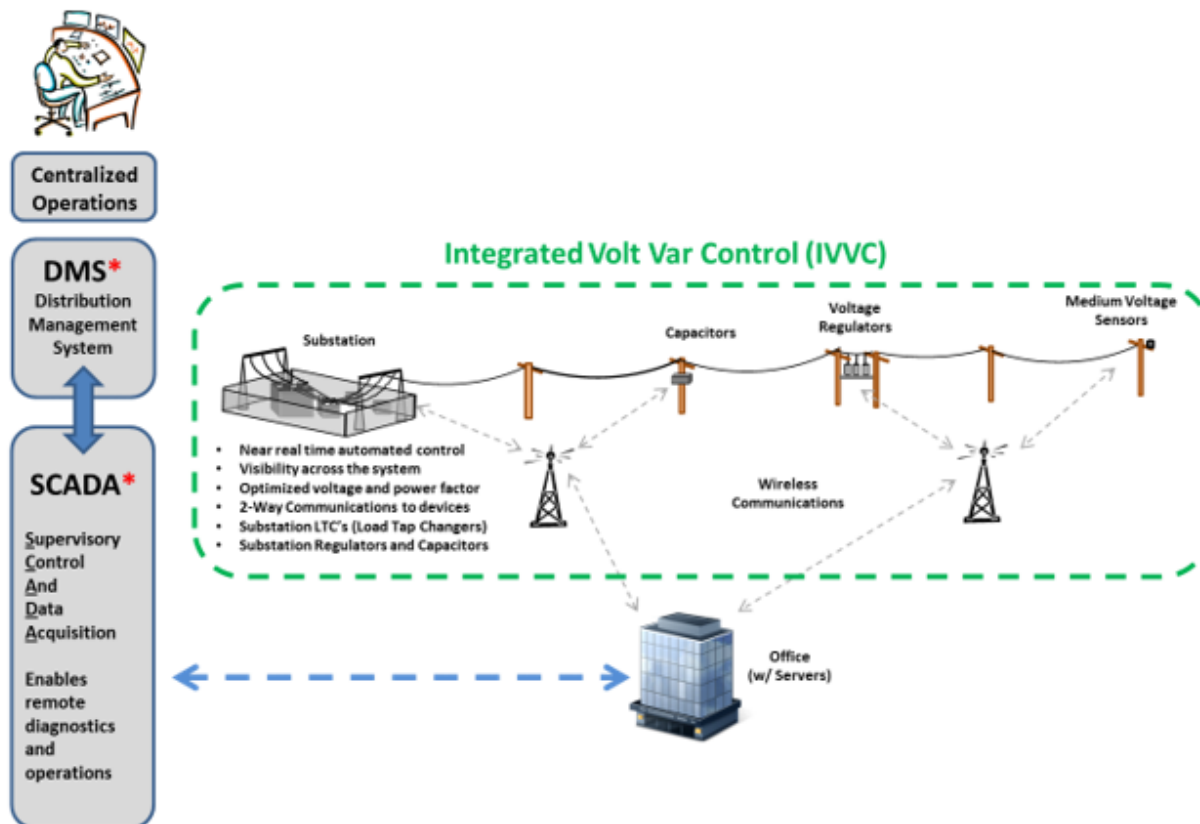
## VOLT - VAR OPTIMIZATION TERMINOLOGY

VVO	<i>Volt-VAR Optimization</i>	Management of Voltage levels and Reactive Power at optimal levels to operate the grid more efficiently
IVVC	<i>Integrated Volt-VAR Control</i>	Full coordination and configuration of intelligent field devices and a management/control system (e.g., DMS, DSCADA) that uses grid data to achieve efficient grid operation while maintaining distribution voltages within acceptable operating limits
DMS	<i>Distribution Management System</i>	Primary information system used to monitor, analyze, and control the distribution grid efficiently and reliably
DSDR	<i>Distribution System Demand Response</i>	Operational mode of VVO that supports peak shaving and emergency MW ( <i>demand</i> ) reduction (alternative to building peaking plant generation)
CVR	<i>Conservation Voltage Reduction</i>	Operational mode of VVO that supports 24/7 voltage reduction and energy conservation (alternative to building base load generation)

## DEP DSDR / CVR ILLUSTRATIVE OVERVIEW



## “HIGH LEVEL” CONCEPTUAL DESIGN



- DSM & SCADA already exists and is not in scope of this project.
- Devices will be integrated into the existing DMS/SCADA





# ENERGY EFFICIENCY, DEMAND SIDE MANAGEMENT AND VOLTAGE OPTIMIZATION



## APPENDIX E: RENEWABLE ENERGY STRATEGY/FORECAST

The growth of renewable generation in the United States continued in 2019. According to EIA, in 2019, 9.1 GW of wind and 5.3 GW of utility-scale solar capacity were installed nationwide. The EIA also estimates 3.7 GW of small scale solar was added as well.<sup>1</sup> Notably, U.S. annual energy consumption from renewable sources exceeded coal consumption for the first time since before 1885.<sup>2</sup>

North Carolina ranked sixth in the country in solar capacity added in 2019 and remains second behind only California in total solar capacity online, while South Carolina ranked seventh in solar capacity added in 2019.<sup>3,4</sup> Duke Energy's compliance with the North Carolina Renewable Energy and Energy Efficiency Portfolio Standards (NC REPS), the South Carolina Distributed Energy Resource Program (SC DER or SC Act 236), the Public Utility Regulatory Policies Act (PURPA) as well as the availability of the Federal Investment Tax Credit (ITC) were key factors behind the high investment in solar.

## RENEWABLE ENERGY OUTLOOK FOR DUKE ENERGY IN THE CAROLINAS

The future is bright for opportunities for continued renewable energy development in the Carolinas as both states have supportive policy frameworks and above average renewable resource availability, particularly for solar. The Carolinas also benefits from substantial local expertise in developing and interconnecting large scale solar projects and the region will benefit from such a concentration of skilled workers. Both states are supporting future renewable energy development via two landmark pieces of legislation, HB 589 in North Carolina (2017) and Act 62 in South Carolina (2019). These provide opportunities for increased renewable energy, particularly for utility customer programs for both large and small customers who want renewable energy. These programs have the potential to add significant renewable capacity that will be additive to the historic reliance on administratively-established standard offer procurement under PURPA in the Carolinas. Furthermore, the Companies' pending request to implement Queue Reform—a transition from a serial study interconnection process to a cluster study process—will create a more efficient

<sup>1</sup> All renewable energy GW/MW represent GW/MW-AC (alternating current) unless otherwise noted.

<sup>2</sup> <https://www.eia.gov/todayinenergy/detail.php?id=43895>.

<sup>3</sup> <https://www.seia.org/states-map>.

<sup>4</sup> <https://www.eia.gov/electricity/data/eia860M/>; February month end data.

and predictable path to interconnection for viable projects, including those that are identified through any current or future procurement structures. It is also worth noting that there are solar projects that appear to be moving forward with 5-year administratively-established fixed price PURPA contracts and additional solar projects that will likely be completed as part of the transition under Queue Reform.

## SUMMARY OF EXPECTED RENEWABLE RESOURCE CAPACITY ADDITIONS

### DRIVERS FOR INCREASING RENEWABLES IN DEP

The implementation of NC HB 589, and the passage of SC Act 62 in SC are significant to the amount of solar projected to be operational during the planning horizon. Growing customer demand, the Federal ITC, and declining installed solar costs continue to make solar capacity the Company's primary renewable energy resource in the 2020 IRP. However, achieving the Company's goal of net-zero carbon emissions by 2050 will require a diverse mix of renewable, and other zero-emitting, load following resources. Wind generation, whether onshore wind generated in the Carolinas or wheeled in from other regions of the country, or offshore wind generated off the coast of the Carolinas, may become a viable contributor to the Company's resource mix over the planning horizon.

The following key assumptions regarding renewable energy were included in the 2020 IRP:

- Through existing legislation such as NC HB 589 and SC Act 62, along with materialization of existing projects in the distribution and transmissions interconnection queues, installed solar capacity increases in DEP from 3,144 MW in 2021 to 4,575 MW in 2035 with approximately 85 MW of usable AC storage coupled with solar included
- Additional solar coupled with storage was available to be selected by the capacity expansion model to provide economic energy and capacity. Consistent with recent trends, total annual solar and solar coupled with storage interconnections were limited to 200 MW per year over the planning horizon in DEP.
- Up to 150 MW of onshore Carolinas wind generation, assumed to be located in the central Carolinas, could be selected by the capacity expansion model annually to provide a diverse



source of economic energy and capacity.

- Compliance with NC REPS continues to be met through a combination of solar, other renewables, EE, and Renewable Energy Certificate (REC) purchases
- Achievement of the SC Act 236 goal of 39 MW of solar capacity located in DEP.
- Implementation of NC HB 589 and SC Act 62 and continuing solar cost declines drive solar capacity growth above and beyond NC REPS requirements

### **NC HB 589 COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY (CPRE)**

NC HB 589 established a competitive solicitation process, known as the Competitive Procurement of Renewable Energy (CPRE), which specified for the addition of up to 2,660 MW of competitively procured renewable resources across the Duke Energy Balancing Authority Areas over a 45-month period ending November 2021. On July 10, 2018, Duke issued a request for bids for the first tranche of CPRE, requesting 600 MW in DEC and 80 MW in DEP. On April 9, 2019 the independent administrator selected 12 projects totaling 515 MW in DEC and two projects totaling 86 MW in DEP. Both DEP projects are third party owned, and one of the DEP projects will be transmission tied in NC and the other will be distribution tied in SC. See the annual CPRE Program Plan included as Attachment II for additional details.

CPRE tranche 2 requested bids for 600 MW in DEC and 80 MW in DEP. The bid window closed March 9, 2020. Initial results showed DEP receiving 6 bids for approximately 440 MW. Five of the bids, representing approximately 365 MW are located within NC and the remaining bid and 75 MW is located within SC. One proposal was submitted with energy storage. Each of the six projects requested transmission interconnection.

One finalist was selected from the initial bid list. This is a 75 MW project located in NC, with plans to employ a single axis tracking configuration. There is no storage associated with this project and the price decrement is approximately \$6.25/MWh. A contract has yet to be executed and the contract negotiation window will close October 15, 2020.

The volume of any future tranches of CPRE will depend on the final results of tranche 2, as well

as, the continued increases in capacity referred to in this document as the “Transition MW”. These “Transition MW” represent the total capacity of renewable generation projects in the combined Duke Balancing Authority area that are (1) already connected; or (2) have entered into purchase power agreements (PPAs) and interconnection agreements (IAs) as of the end of the 45-month competitive procurement period, and which are not subject to curtailment or economic dispatch. The total CPRE target of 2,660 MW will vary based on the amount of Transition MW at the end of the 45-month period, which NC HB 589 expected to total 3,500 MW. If the aggregate capacity in the Transition MW exceeds 3,500 MW, the competitive procurement volume of 2,660 MW will be reduced by the excess amount and vice versa. As of May 2020, there is approximately 4,020 MW of solar capacity and 280 MW of non-solar capacity that meet NC HB 589’s definition of “Transition MW”, meaning CPRE will be reduced by a minimum of 800 MW. The company believes the Transition may ultimately exceed 3,500 MW by as much as 1,850 MW, and possibly more depending on the extent to which SC Act 62 and Interconnection Queue reform drive new solar growth in SC by the end of the 45-month CPRE period.

## NC AND SC INTERCONNECTION QUEUES

Through the end of 2019, DEP had nearly 2,750 MW of utility scale solar on its system, with approximately 240 MW interconnecting in 2019. When renewable resources were evaluated for the 2020 IRP, DEP reported approximately 240 MW of third-party solar construction in progress and approximately 7,000 MW in the interconnection queue. Details of the number of pending projects and pending capacity by state are included in Appendix K.

Projecting future solar connections from the interconnection queue presents a significant challenge due to the large number of project cancellations, ownership transfers, interconnection studies required, and the unknown outcome of which projects will be selected through the CPRE program. Additionally, any future efforts to reform the transmission or distribution interconnection queues could cause these projections to vary.

DEP’s contribution to the Transition depends on many variables including connecting projects under construction, the expected number of renewable projects in the queue with a PPA and IA, SC Act 62, and SC DER Program Tier I. As of May 31, 2020, DEP had nearly 450 MW of solar capacity with a PPA and IA, and roughly 140 MW of non-solar renewable capacity with PPA’s that extend through the 45-month CPRE period. A number of additional projects in the queue are

expected to acquire both a PPA and IA prior to the expiration of the 45-month period defined in NC HB 589, potentially resulting in approximately an additional 700 MW contributing to the Transition. In total, DEP may contribute roughly three-quarters of the Transition MW with DEC accounting for the remaining one-quarter.

## NC REPS COMPLIANCE

DEP remains committed to meeting the requirements of NC REPS, including the solar, poultry waste, and swine waste set-asides, and the general requirement, defined as the total REPS requirement net of the three set-asides, which will be met with additional renewable and energy efficiency resources. DEP's long-term general compliance needs are expected to be met through a combination of renewable resources, including RECs obtained through the NC HB 589 competitive procurement process. For details of DEP's NC REPS compliance plan, please reference the NC REPS Compliance Plan, included as Attachment I to this IRP.

## NC HB 589 COMPETITIVE PROCUREMENT AND UTILITY-OWNED SOLAR

DEP continues to evaluate utility-owned solar additions to grow its renewables portfolio. DEP owns and operates four utility-scale solar projects, totaling 141 MW-AC, as part of its efforts to encourage emission free generation resources and help meet its compliance targets:

- Camp Lejeune Solar Facility – 13 MW, located in Onslow County, NC placed in service in November 2015;
- Warsaw Solar Facility – 65 MW, located in Duplin County, NC placed in service in December 2015;
- Fayetteville Solar Facility – 23 MW, located in Bladen County, NC placed in service in December 2015; and
- Elm City Solar Facility – 40 MW, located in Wilson County, NC placed in service in March 2016.

No more than 30% of the CPRE Program requirement may be satisfied through projects in which Duke Energy or its affiliates have an ownership interest at the time of bidding. Duke Energy

Renewables was awarded approximately 20% of the capacity selected in the first tranche of CPRE. NC HB 589 does not stipulate a limit for DEP's option to acquire projects from third parties that are specifically proposed in the CPRE Request for Proposals (RFP) as acquisition projects, though any such project will not be procured unless determined to be among the most cost-effective projects submitted.

## ADDITIONAL FACTORS IMPACTING FUTURE SOLAR GROWTH

According to BloombergNEF and the Solar Energy Industries Association (SEIA), the solar industry has not been immune to the impacts of COVID-19<sup>56</sup>. The industry has experienced a significant loss in employment in the United States with most of the job losses and impacts associated with distributed generation. The pandemic has certainly introduced supply chain risks, and anecdotal evidence suggests that project financing is becoming more challenging, especially with the likely contraction of tax equity markets. Offsetting these concerns is a more diversified supply chain, especially in the United States, which helps to mitigate some of the supply chain risks. In addition, the U.S. Congress has passed several bills to help provide stimulus and liquidity in the markets, and there are various infrastructure legislative proposals that contain incentives to help the solar industry to continue to move forward. Taken together, the prevailing consensus seems to be that utility scale projects may be delayed, but it is unlikely that there will be large scale cancellations.

<sup>5</sup> <https://www.powerengineeringint.com/renewables/bnef-predicts-slow-down-in-clean-energy-economy-due-to-covid-19/>.

<sup>6</sup> <https://www.seia.org/sites/default/files/2020-05/SEIA-COVID-Impacts-National-Factsheet.pdf>.

Beyond the immediate COVID-19 concerns, there are numerous other factors that impact the Company's forecast of future solar growth in the Carolinas. Key among these is potential changes in the Company's avoided cost in either NC or SC, as these may impact the development of projects under PURPA, NC HB 589, and SC Act 62. Avoided cost forecasts are subject to variability due to changes in factors such as natural gas and coal commodity prices, system energy and demand requirements, the level and cost of generation ancillary service requirements, and interconnection costs. PURPA requires utilities to purchase power from QFs at or below the utility's avoided cost rates. NC HB 589 requires that competitive bids are priced below utility's avoided cost rates, as approved by the NCUC, in order to be selected. Given the potential for changes in the avoided cost rates, the installed cost of solar remains a critical input for forecasting how much solar will materialize in the future. This stems from the fact that the actual cost of solar is not related to the PURPA avoided cost rates, even though solar investment was possible in the past at those avoided cost rates.

Installed solar costs encompass many variables, including physical components such as PV modules, inverters, electrical, and structural equipment, as well as engineering design, O&M and interconnection charges, to name a few. Solar panel prices have been declining at a fairly significant rate over the last decade and are expected to continue this decline into the future, although the Section 201 tariffs that were enacted in 2018 will continue to impact module costs at least through 2021. The tariff is related to solar modules and cells and is set at 20% for the remainder of 2020 and dropping to 15% in 2021, which would be the last year the tariffs are in effect. Additional factors that could put upward pressure on solar costs include direct interconnection costs, as well as costs incurred to maintain the appropriate operational control of the facilities. Finally, as panel prices have decreased, there has been more interest in installing single-axis tracking (SAT) systems (as demonstrated in CPRE tranches 1 and 2) and/or systems with higher inverter load ratios (ILR) which change the hourly profile of solar output and increase expected capacity factors. DEC models fixed tilt and SAT system hourly profiles with a range of ILRs as high as 1.6 (DC/AC ratio).

In summary, there is a great deal of uncertainty in both the future avoided costs applied to solar and the expected price of solar installations in the years to come. As a result, the Company will continue to closely monitor and report on these changing factors in future IRP and competitive procurement filings.

## NC HB 589 CUSTOMER PROGRAMS

In addition to the CPRE program, NC HB 589 offers direct renewable energy procurement for major military installations, public universities, and other large customers, as well as a community.

solar program. These programs are in addition to the existing SC Act 236 Programs and upcoming SC Act 62 programs.

As part of NC HB 589, the renewable energy procurement program enables large customers to procure renewable energy attributes from new renewable energy resources and receive a bill credit for the energy and capacity provided to DEC's system. The program allows for up to 600 MW of total capacity, with set asides for military installations (100 MW of the 600 MW) and the University of North Carolina (UNC) system (250 MW of the 600 MW). The 2020 IRP base case assumes all 600 MW of this program materialize, with the DEC/DEP split expected to be roughly 65/35. If all 600 MW are not utilized, the remainder will roll back to the competitive procurement, increasing its volume.

The community solar portion of NC HB 589 calls for up to 20 MW of shared solar in DEP. This program is similar to the SC Act 236 Shared Solar program in that it allows customers who cannot or do not want to put solar on their property to take advantage of the economic and environmental benefits of solar by subscribing to the output of a centralized facility. A key difference between the SC Act 236 Shared Solar program and the NC HB 589 Shared Solar program is that HB 589 does not allow the program to be subsidized. Customers must be credited at avoided cost and projects cannot be greater than 5MW. An RFP issued in 2019 with these parameters resulted in no bids. The 2020 IRP Base Cases assume that all 20 MW of the NC HB 589 shared solar program materializes starting in 2022.

NC HB 589 also established a rebate program for rooftop solar, limited to 10 MW of installed capacity per utility per year over 2018 through 2022. There are rules governing residential and non-residential customers, along with set asides for nonprofit organizations. Any set asides not used by year end 2022 will be reallocated for use by any customer type who meets the necessary qualifications. Since its inception in 2018, the rebate program has spurred greater interest in solar installations and therefore, more net metered customers in NC. Residential and

non-residential capacity limits were quickly fully subscribed in 2018, 2019 and 2020. DEC NC installed approximately 13 MW of rooftop solar in 2018 and approximately 23 MW of rooftop solar in 2019. Through May of 2020, installed rooftop solar capacity is approximately 11 MW. For further discussion of rooftop solar projections, see below, as well as Appendix C.

## SC ACT 236 AND SC ACT 62

Steady progress continues to be made with the first two tiers of the SC DER Program summarized below, completion of which would unlock the third tier:

- **Tier I:** 13 MW of solar capacity from facilities each  $>1$  MW and  $< 10$  MW in size.
- **Tier II:** 13 MW of behind-the-meter solar facilities for residential, commercial and industrial customers, each  $\leq 1$  MW, 25% of which must be  $\leq 20$  kilowatts (kW). Since Tier II is behind the meter, the expected solar generation is embedded in the load forecast as a reduction to expected load.
- **Tier III:** Investment by the utility in 13 MW of solar capacity from facilities each  $>1$  MW and  $<10$  MW in size. Upon completion of Tiers I and II (to occur no later than 2021), the Company may directly invest in additional solar generation to complete Tier III.

DEP has executed two PPAs to complete Tier I, resulting in 15 MW which are currently operational. Tier II incentives have resulted in growth in private solar in DEP, as nearly 18 MW of rooftop solar has been installed in DEP SC.

The Company launched its first Shared Solar program as part of Tier I. Duke Energy designed its initial SC Shared Solar program to have appeal to residential and commercial customers who rent or lease their premises, residential customers who reside in multifamily housing units or shaded housing or for whom the relatively high up-front costs of solar PV make net metering unattainable, and non-profits who cannot monetize the ITC. To make the program financially feasible, the subscription fee is subsidized by the ratebase. The program capacity is 1 MW including 200 kW set aside for low to moderate income (LMI) customers earning less than 200% of the federal poverty level. The unreserved 800 kW of capacity sold out within 10 months due to the program's strong economic proposition. As of the end of June 2020, low to moderate income customers



have subscribed to 336 kW.

**TABLE E-1**  
**DEP SHARED SOLAR PROGRAM**

	AVERAGE SUBSCRIPTION KW PER PARTICIPANT	CUSTOMERS	CAPACITY (KW)
Residential LMI	2	168	400
Residential Non-LMI	7.19	82	600
Non-Residential	18	1	

SC Act 62 passed in South Carolina on May 16, 2019. SC Act 62 will likely drive additional PURPA solar as DEP must offer fixed price PPAs to certain small power producers at avoided cost for a minimum contract term of 10 years. The 10-year rate is applicable for projects located in SC until DEP has executed IAs and PPAs with aggregated nameplate capacity equal to 20 percent of the previous 5-year average of DEP's SC retail peak load, or roughly 260 MW. After 260 MW have executed IAs and PPAs the Commission will determine conditions, rates, and terms of length for future contracts. Given there is roughly 2,400 MW of solar pending in DEP SC, the Company expects to meet 260 MW within the IRP planning period. The Company intends to closely monitor the capacity with executed IAs and PPAs, evaluate impacts on the NC HB 589 Transition MW and corresponding reduction in CPRE volume. Once the 260 MW threshold is reached, the PSCSC will determine the term limit for PURPA contracts in its sole discretion.

SC Act 62 also called for additional customer programs, requiring the utilities to file voluntary renewable energy programs within 120 days of SC Act 62 passing, and encouraging additional community solar. The Company has a proposed voluntary renewable energy program pending before the Commission, which would create a 150 MW program for DEC and DEP SC combined (37 MW in DEP) offering up to 20-year PPAs. The Companies are considering whether additional community solar should be pursued.

Finally, SC Act 62 lifted the cap on net metering, requiring the Company to offer full retail rate net metering through June 1, 2021, as approved through proceedings under Act 236. As required by

the legislation, the Public Service Commission of South Carolina opened a docket in May 2019 to establish a solar choice metering tariff to go into effect for customer applications received after May 31, 2021 which would replace the metering tariff for new installations.<sup>7</sup> The Company expects net metering adoption to pick up to comparable levels of adoption observed in DEP-SC in 2017/2018 through June 2021. Future adoption after that date will be determined based upon the solar choice tariff terms approved by the SC PSC.

## WIND

DEP considers wind a potential energy resource in the short and long term to support increased renewable portfolio diversity, an important resource for achieving the Company's 2050 net-zero carbon emission goal, as well as long-term general compliance need. However, sourcing wind remains challenging, whether the wind is imported from other states, sited within the Carolinas, or sited offshore.

In 2020, offshore wind energy is becoming a more viable alternative, but only one project near the Carolinas, the Avangrid Kitty Hawk project off the coast of North Carolina, has the necessary Bureau of Ocean Energy Management (BOEM) offshore lease to begin construction. Several call areas began the process of evaluation along the North and South Carolina border but stalled out in recent years as BOEM refocused their efforts to areas with higher demand. These call areas could eventually become new leasing areas, but first BOEM's Task Force will need a representative from South Carolina to restart the permitting and approvals process.

The Company continues to evaluate options for increasing access to offshore wind energy into the Carolinas, however the cost to transport wind energy from the coast to the load centers located in central North Carolina and South Carolina is significant. In 2012, the North Carolina Transmission Planning Collaborative (NCTPC) released a study that estimated transmission upgrade costs for moving wind into the Carolinas in a few different scenarios: the costs ranged from approximately \$930M to \$1,730M. While the Company continues working with the NCTPC to update estimates for integrating offshore wind into the DEP and DEC territories, the Company expects those costs to increase significantly as the costs to site and build new transmission infrastructure has increased over the last decade. For further discussion of the transmission costs associated with moving offshore wind from the coast to load centers in the Carolinas, see Chapter 7.

<sup>7</sup> PSCSC Docket 2019-182E.

Wind energy generated onshore in the Carolinas presents other challenges. The wind capacity (speeds and duration) are generally best in the mountains and along the coast of the Carolinas, but these locations also have hurdles. While the moratorium on building land-based wind in NC has recently expired, the Mountain Ridge Protection Act prevents building wind on ridgetops, and coastal tourism often deters siting on land along the coast. Aside from the policy barriers, there is a significant need for meteorological towers to collect wind speed history in key areas across the Carolinas to gain confidence in predicted capacity factors. The Carolinas onshore wind profiles used in this IRP were provided by a third party and may not be based on wind speeds measured near the expected hub heights.

While the Company is working to improve the quality of Carolinas onshore wind profiles for use in future IRPs it is expected that wind generation located in the central portion of the Carolinas would generally have much lower output than sites located on the coast or mountains, but the benefit of these sites would likely be lower transmission costs. These lower costs could potentially outweigh effects of lower output, particularly since their wind profiles are generally complementary to solar generation.

On-shore wind located outside of the Carolinas presents both economic and logistical challenges associated with constructing significant transmission infrastructure. In August 2017, DEC issued an RFP for delivered energy, capacity, and associated RECs from wind projects up to 500 MW. While bids received were not economically valuable enough to pursue, the Company has continued to evaluate potential projects. Out-of-state transmission costs and availability are one of the complicating factors for importing wind from out of state.

While wind energy continues to face challenges, the Company believes wind energy can become a viable resource by the end of the planning horizon. For this reason, Central Carolinas wind was included as an available resource in the base case, and the high renewable case includes both offshore and central US located wind as resources in the 2030 to 2035 timeframe. Additionally, the Company included higher levels of offshore wind in the 70% CO<sub>2</sub> Reduction: High Wind and No New Gas Generation portfolios to demonstrate how diversifying the Company's resource mix can help achieve aggressive carbon emission reduction goals. While the majority of offshore wind was allocated to DEP in the No New Gas Generation case, it is possible that future policy may provide for cost and benefit sharing of emerging carbon free resources, such as offshore wind, across all customers in both DEP and DEC in order to equitably advance such technologies. For a more detailed summary of these portfolios, see Chapter 12 and Appendix A.

## SUMMARY OF EXPECTED RENEWABLE RESOURCE CAPACITY ADDITIONS:

### BASE WITH CARBON POLICY

The 2020 IRP Base with Carbon Policy case incorporates the projected and economically selected renewable capacities shown below. This case includes renewable capacity components of the Transition MW, such as capacity required for compliance with NC REPS, PURPA purchases, the SC DER Program, NC Green Source Rider (pre-HB 589 program), and the additional three components of NC HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). The Base Case also includes additional projected solar growth beyond NC HB 589, including opportunities for growth from SC Act 62 and the materialization of additional projects in the transmission and distribution queues. The Base Case does not attempt to project future regulatory requirements for additional solar generation, such as new competitive procurement offerings after the current CPRE program expires.

However, it is the Company's belief that continued declines in the installation cost of solar and storage will enable coupled "solar plus storage" systems, to contribute to energy and capacity needs. Additionally, the inclusion of a CO<sub>2</sub> emissions tax, or some other carbon emissions reduction policy, would further incentivize expansion of solar resources in the Carolinas. In the 2020 IRP, the capacity expansion model selected additional solar coupled with storage averaging 200 MW annually beginning in 2029 if a CO<sub>2</sub> tax were implemented in the 2025 timeframe.

Unlike the first tranche of CPRE, the second tranche of CPRE did not yield any solar plus storage projects. The Company continues to believe that the combination of falling storage costs in addition to the most recent avoided cost rate structures proposed in both NC and SC provide strong price incentives for QFs to shift energy from lower priced energy-only hours to hours that have higher energy and capacity prices. This rate design provides incentives to encourage storage additions to solar projects. The Company this year is also projecting that a significant amount of incremental solar beyond NC HB 589 will be coupled with storage. The 2020 base case assumes storage is DC coupled with solar, has a four-hour duration, and the capacity of the battery storage is 25% of the capacity of the solar. In total, DEP expects approximately 1,514 MW of solar coupled with approximately 380 MW of storage by the end of 2035.

Additionally, Phase 1 of NREL's Integration of Carbon Free Resources Study, highlighted the benefit storage provides by reducing the curtailment of solar resources as significant levels of solar are added to the DEP system and create more excess energy conditions. In fact, at current levels of solar investment in DEP, curtailment is becoming a more likely outcome, particularly during periods of low load and high solar output. For modeling purposes, the Company assumes that, beginning in 2026, incremental solar additions in DEP must include storage to limit marginal curtailment of new solar resources to less than 20% of solar energy produced. This constraint will be evaluated in future IRPs as storage becomes more integrated on the DEP system.

Finally, as solar generation is expected to continue its expansion in DEP, interconnecting several thousand MW of new solar generation will likely require new transmission projects and could create logistical constraints due to limited transmission outage windows as these projects are implemented. For the last five years, DEP and DEC have interconnected approximately 500 MW of solar combined annually. While interconnections may potentially exceed those levels in the short-term, over the planning horizon, for base case planning purposes, the Company assumed interconnections were limited to 500 MW on an annual average basis. Since the majority of growth is expected in DEC, the DEP specific interconnection constraint was assumed to be 200 MW annually. The Company will continue to monitor interconnections, and should new, larger projects request interconnection to the DEP system or other efficiencies be realized, the level of interconnections may increase.

The Company anticipates a diverse renewable portfolio including solar, biomass, hydro, storage fed by solar, wind and other resources. Actual results could vary substantially for the reasons discussed in this appendix, as well as, other potential changes to legislative requirements, tax policies, technology costs, carbon prices, ancillary costs, interconnection costs, and other market forces. The details of the forecasted capacity additions, including both nameplate and contribution to winter and summer peaks are summarized in Table E-2 below.

TABLE E-2  
DEP BASE WITH CARBON POLICY TOTAL RENEWABLES

DEP BASE RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	2,888	0	284	0	3,171	1,011	0	284	0	1,294	29	0	284	0	319
2022	3,144	0	146	0	3,291	1,092	0	146	0	1,238	31	0	146	0	1,375
2023	3,430	0	135	0	3,565	1,134	0	135	0	1,270	34	0	135	0	1,439
2024	3,641	14	131	0	3,786	1,166	8	131	0	1,305	36	3	131	0	1,470
2025	3,850	13	131	0	3,995	1,190	8	131	0	1,329	39	3	131	0	1,503
2026	4,128	13	120	0	4,262	1,218	7	120	0	1,345	41	3	120	0	1,534
2027	4,184	88	120	0	4,392	1,223	48	120	0	1,391	42	22	120	0	1,583
2028	4,239	163	116	0	4,518	1,229	88	116	0	1,433	42	41	116	0	1,590
2029	4,294	237	60	0	4,591	1,234	128	60	0	1,422	43	59	60	0	1,541
2030	4,323	436	43	0	4,802	1,237	234	43	0	1,515	43	109	43	0	1,675
2031	4,352	634	43	0	5,029	1,240	340	43	0	1,623	44	158	43	0	1,824
2032	4,331	856	42	0	5,228	1,238	460	42	0	1,740	43	214	42	0	1,900
2033	4,311	1,076	42	150	5,579	1,236	581	42	12	1,870	43	269	42	53	2,137
2034	4,290	1,296	41	300	5,928	1,234	701	41	24	2,000	43	324	41	105	2,313
2035	4,270	1,514	41	450	6,276	1,232	822	41	36	2,131	43	379	41	158	2,361

Data presented on a year beginning basis.

Solar includes 0.5% per year degradation.

Capacity listed excludes REC Only Contracts.

Solar contribution to peak based on 2018 Astrapé analysis; solar with storage contribution to peak based on 2020 Astrapé ELLC study.



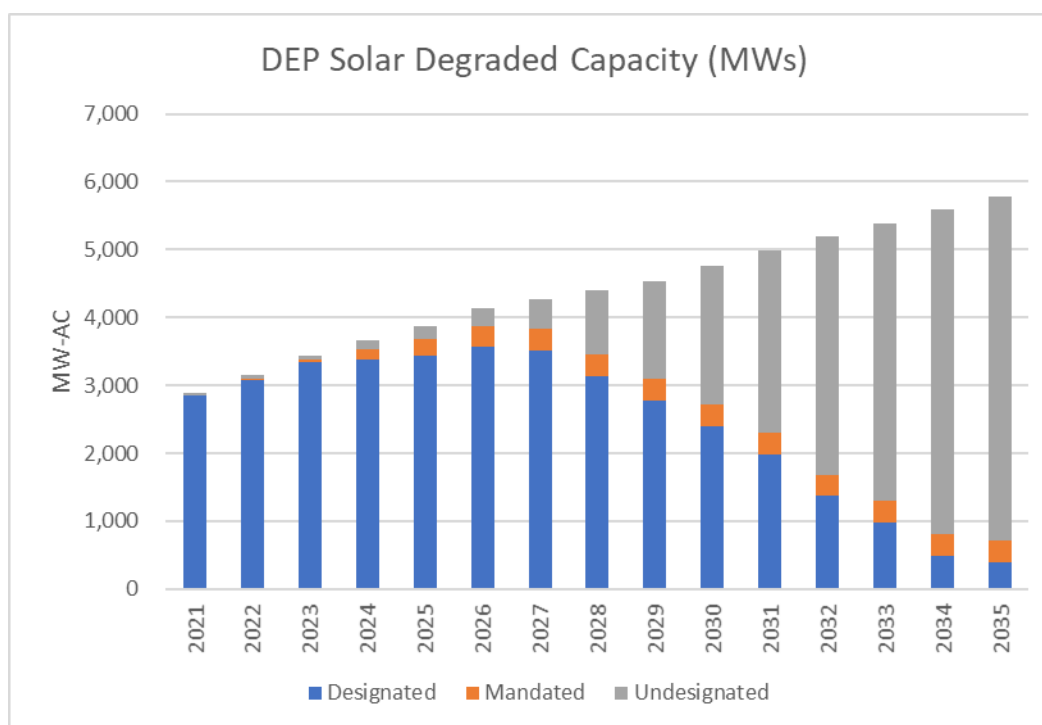
While solar is not at its maximum output at the time of DEP's expected peak load in the summer, solar's contribution to summer peak load is large enough that it will likely push the time of summer peak to a later hour if solar generation levels continue to increase. However, solar is unlikely to have a similar impact on the morning winter peak due to little solar output in the morning hours. Solar capacity contribution percentages to summer and winter peak demands are assumed to be the same as those used in the 2019 IRP. Note, however the solar contribution to peak values now also include additional contributions provided by storage coupled with solar, assumed to be 100% of the storage capacity installed based on the results of the Capacity Value of Battery Storage study discussed in Appendix H.

As a number of solar contracts are expected to expire over the IRP planning period, the Company is additionally breaking down its solar forecast into three buckets described below:

- **Designated:** Contracts that are already connected today or those who have yet to connect but have an executed PPA are assumed to be designated for the duration of the purchase power contract.
- **Mandated:** Capacity that is not yet under contract but is required through legislation (examples include future tranches of CPRE, the renewables energy procurement program for large customers, and community solar under NC HB 589 as well as SC Act 236)
- **Undesignated:** Additional capacity projected beyond what is already designated or mandated. Expiring solar contracts are assumed to be replaced in kind with undesignated solar additions. Such additions may include existing facilities or new facilities that enter into contracts that have not yet been executed.

The figure below shows DEP's breakdown of these three buckets through the planning period. Note for avoided cost purposes, the Company only includes the Designated and Mandated buckets in the base case. For determining the cost cap pricing in the second tranche of CPRE, the Company includes the Designated bucket only.

**FIGURE E-1**  
**DEP SOLAR DEGRADED CAPACITY (MW)**



## HIGH & LOW RENEWABLE CASES

Given the significant volume and uncertainty around solar investment, high and low solar portfolios were compared to the Base Case described above. The portfolios do not envision a specific market condition, but rather the potential combined effect of a number of factors. For example, the high sensitivity could occur given events such as high carbon prices, lower solar capital costs, economical solar plus storage, continuation of renewable subsidies, and/or stronger renewable energy mandates. Additionally, the high case also considers a combination of onshore and offshore wind as viable resources beginning in the 2030 timeframe. On the other hand, the low sensitivity may occur given events such as lower fuel prices for more traditional generation technologies, higher solar installation and interconnection costs, and/or high ancillary costs which may drive down the economic viability of future incremental solar additions. These events may cause solar projections to fall short of the Base Case if the CPRE, renewable energy procurement for large customers, and/or the community solar programs of HB 589 do not materialize or are delayed.

Tables 5-B and 5-C below provide the high and low solar nameplate capacity summaries, as well as, their corresponding expected contributions to summer and winter peaks. For more details on these sensitivities see Appendix A.

**TABLE E-3**  
**DEP HIGH RENEWABLES SENSITIVITY**

DEP HIGH RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	2,888	0	284	0	3,171	1,011	0	284	0	1,294	29	0	284	0	312
2022	3,144	0	146	0	3,291	1,092	0	146	0	1,238	31	0	146	0	178
2023	3,430	0	135	0	3,565	1,134	0	135	0	1,270	34	0	135	0	169
2024	3,641	14	131	0	3,786	1,166	8	131	0	1,305	36	3	131	0	171
2025	3,850	13	131	0	3,995	1,190	8	131	0	1,329	39	3	131	0	173
2026	4,128	13	120	0	4,262	1,218	7	120	0	1,345	41	3	120	0	165
2027	4,109	229	120	0	4,458	1,216	125	120	0	1,461	41	57	120	0	218
2028	4,089	446	116	0	4,652	1,214	244	116	0	1,574	41	112	116	0	269
2029	4,070	677	60	0	4,807	1,212	372	60	0	1,644	41	169	60	0	270
2030	4,051	904	43	0	4,997	1,210	498	43	0	1,750	41	226	43	0	309
2031	4,031	1,138	43	60	5,272	1,208	629	43	14	1,894	40	285	43	37	405
2032	4,011	1,383	42	120	5,556	1,206	766	42	29	2,043	40	346	42	74	501
2033	3,992	1,647	42	180	5,861	1,204	914	42	43	2,203	40	412	42	111	604
2034	3,974	2,084	41	390	6,489	1,202	1,160	41	70	2,473	40	521	41	200	802
2035	3,955	2,533	41	615	7,144	1,201	1,413	41	100	2,754	40	633	41	299	1,013

Data presented on a year beginning basis.

Solar includes 0.5% per year degradation.

Capacity listed excludes REC Only Contracts.

Solar contribution to peak based on 2018 Astrapé analysis; solar with storage contribution to peak based on 2020 Astrapé ELLC study.

**TABLE E-4**  
**DEP LOW RENEWABLES SENSITIVITY**

DEP LOW RENEWABLES - COMPLIANCE + NON-COMPLIANCE															
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	2,888	0	284	0	3,171	1,011	0	284	0	1,294	29	0	284	0	317
2022	3,144	0	146	0	3,291	1,092	0	146	0	1,238	31	0	146	0	1,369
2023	3,430	0	135	0	3,565	1,134	0	135	0	1,270	34	0	135	0	1,404
2024	3,641	14	131	0	3,786	1,166	8	131	0	1,305	36	3	131	0	1,434
2025	3,850	13	131	0	3,995	1,190	8	131	0	1,329	39	3	131	0	1,462
2026	4,128	13	120	0	4,262	1,218	7	120	0	1,345	41	3	120	0	1,464
2027	4,109	13	120	0	4,242	1,216	7	120	0	1,343	41	3	120	0	1,464
2028	4,089	13	116	0	4,219	1,214	7	116	0	1,337	41	3	116	0	1,460
2029	4,070	163	60	0	4,293	1,212	90	60	0	1,361	41	41	60	0	1,452
2030	4,051	312	43	0	4,406	1,210	172	43	0	1,425	41	78	43	0	1,526
2031	4,031	461	43	0	4,534	1,208	254	43	0	1,505	40	115	43	0	1,563
2032	4,011	609	42	150	4,811	1,206	336	42	12	1,596	40	152	42	53	1,643
2033	3,992	756	42	300	5,090	1,204	419	42	24	1,689	40	189	42	105	1,720
2034	3,974	902	41	450	5,367	1,202	501	41	36	1,781	40	225	41	158	1,805
2035	3,955	1,047	41	600	5,644	1,201	584	41	48	1,874	40	262	41	210	1,895

Data presented on a year beginning basis.

Solar includes 0.5% per year degradation.

Capacity listed excludes REC Only Contracts.

Solar contribution to peak based on 2018 Astrapé analysis; solar with storage contribution to peak based on 2020 Astrapé ELLC study.





## FUEL SUPPLY



Corrected 11.06.2020

## APPENDIX F: FUEL SUPPLY

Duke Energy Progress' current fuel usage consists of a mix of coal, natural gas and uranium. Oil is used for peaking generation and natural gas continues to play an increasing role in the fuel mix due to lower pricing and the addition of a significant amount of combined cycle. A brief overview and issues pertaining to each fuel type are discussed below.

### NATURAL GAS



During 2019 New York Mercantile Exchange (NYMEX) Henry Hub natural gas prices averaged approximately \$2.51 per million BTU (MMBtu) and U.S. lower-48 net dry production averaged approximately 92 billion cubic feet per day (BCF/day). Natural gas spot prices at the Henry Hub averaged approximately \$2.00 per MMBtu in January 2020, while spot pricing decreased throughout the remaining winter months and averaged \$1.75 per MMBtu at the end of March 2020. The lower short-term spot prices in February and March 2020 were driven by both fundamental supply and demand factors as winter temperatures remained mild.

Average daily U.S. net dry production levels of approximately 92 BCF/day in the first quarter of 2020 were 4.2 BCF/day higher than the comparable period in 2019. The U.S. Energy Information Administration (EIA) is forecasting a decrease this year from a reported 93.1 BCF/day in April, to 85.4 BCF/day by December. Most of this decline in production will be seen in the Appalachian region. Prices are discouraging producers from engaging in natural gas-directed drilling, and in the Permian region, where low oil prices reduce associated gas output from oil-directed wells. Current forecasts show dry natural gas production averaging 84.9 BCF/day in 2021, rising in the second half of the year in response to higher prices.

Following this year's winter withdrawal season, U.S. working gas in storage levels were reported to be at approximately 2.3 trillion cubic feet (TCF) as of April 30, 2020, coming in 20% above the five-year average between 2015-2019. Lower-48 U.S. overall demand in the first quarter of 2020 was lower than normal due to the above average temperatures throughout the winter months.

While Henry Hub spot prices averaged \$1.63 per MMBtu during the first week of June 2020, the EIA forecasts natural gas prices will generally rise through 2020 as a decline in U.S. production is seen. Spot prices at Henry Hub are being forecasted by the EIA to average \$2.14 per MMBtu this year, and

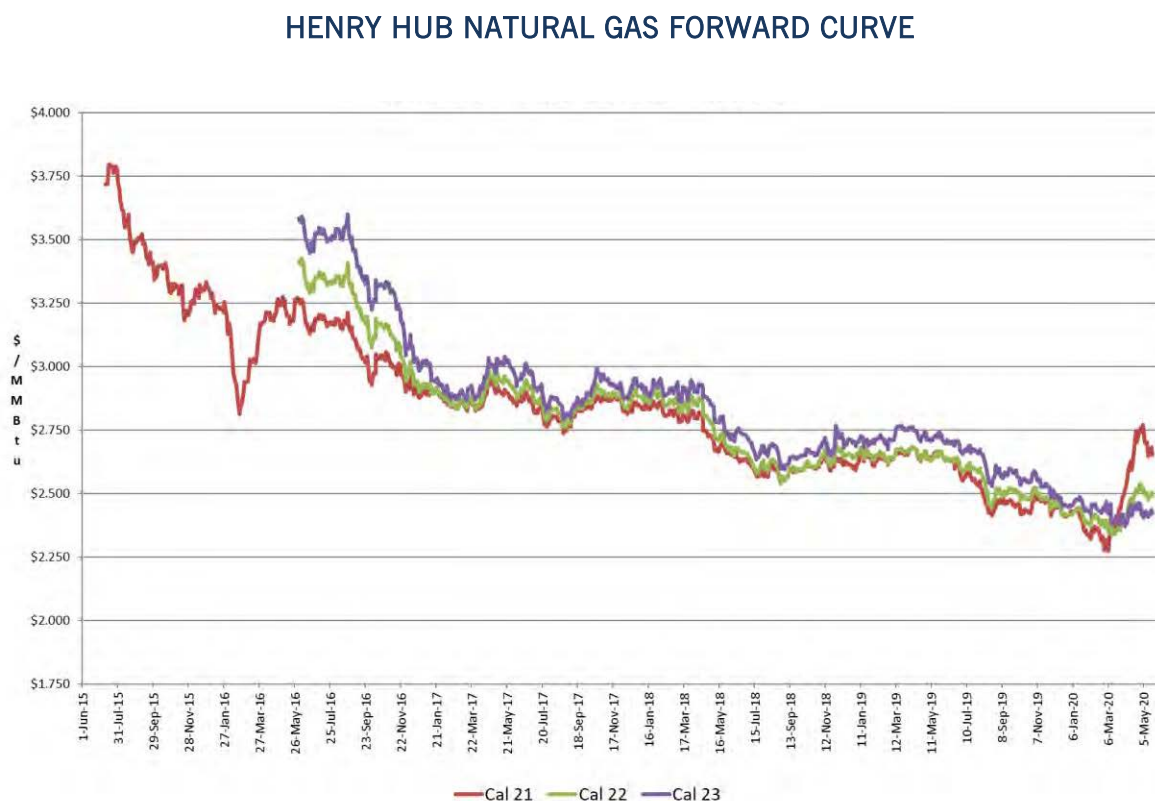


then increasing to an annual average of \$2.89 in 2021 as a result of lower natural gas production.

The EIA is expecting domestic natural gas consumption to see a 3.4 BCF/day decline compared to 2019. Overall U.S. forecasts for the year are down mainly due to reduced economic activity related to COVID-19, led by a decrease in demand during the first quarter as a result of milder-than-normal temperatures. Per the EIA's short-term energy outlook (STEO) released on May 26, 2020, natural gas consumption in the residential and commercial sectors is forecasted to decrease by 3.7% and 6.9%, respectively. Although those two sectors account for a small fraction of U.S. natural gas consumption outside of winter months when heating demand is high, the EIA expects weaker economic conditions in the coming months to further reduce average consumption in the commercial sector. With the weak economic conditions, the EIA also expects industrial natural gas demand to decline in the U.S. from an average of 21.4 BCF/day in 2019, to an average of 19.9 BCF/day in 2020, which will be at its lowest point since the summer of 2016.

Following the first half of 2020 short-term energy outlook, which expected natural gas used for electric power to grow 1.6 BCF/day compared to the first half of 2019 as a result of low natural gas prices, and lower-than-expected natural gas capacity additions, the EIA forecasts to see a decline during the second half of 2020. With natural gas prices forecasted to rise during that time, the STEO shows a reduction of natural gas consumption for electric power by 2.2BCF/day compared to the second half of 2019. The EIA's most recent short-term energy outlook also reports an expected rise in the May Henry Hub spot price from \$1.88/MMBtu to \$2.94/MMBtu by December 2020. These higher natural gas prices will result in some coal-fired generation units to become more economical to dispatch versus natural gas-fired units. EIA expects the share of U.S. total utility-scale electricity generation from natural gas-fired power plants to rise from 37% in 2019 to 39% in 2020. As a result, coal's forecast share of electricity generation falls from 24% in 2019 to 19% in 2020. According to Baker Hughes, as of June 5, 2020, the U.S. rig count was at 284. This is 691 less than this time last year.

FIGURE F-1  
HENRY HUB NATURAL GAS PRICE FORWARD CURVE



Looking forward, the forward 5 and 10-year observable market curves are at \$2.39 and \$2.53 per MMBtu, respectively, as of the June 5, 2020 close. In addition, as of the close of business on June 5, 2020, the one (1), three (3) and five (5) years strips averaged approximately \$2.48 per MMBtu. As illustrated with these price levels and relationships, the forward NYMEX Henry Hub price curve is relatively flat with the periods of 2022 and 2023 currently trading at discounts to 2021 prices. The gas market is expected to remain relatively stable due to the recent balancing act of lower production to account for the lack of demand during the COVID-19 pandemic. Demand for natural gas from the power sector for 2020 is expected to be higher than coal generation due to coal retirements, which are tied to the implementation of the EPA's MATS rule covering mercury and acid gasses. The North American gas resource picture is a story of unconventional gas production dominating the gas industry. Shale gas now accounts for approximately 97% of net natural gas production today. As noted earlier, per the EIA's short-term outlook dated May 12, 2020, the EIA expects dry gas production to average 89.8 BCF/day by the end of 2020 and fall by 5 BCF/day in 2021 to 84.9 BCF/day. The United States is a net exporter of natural gas, with net exports expected to average 7.3 BCF/day in 2020. According

to the EIA forecast, US Liquified Natural Gas (LNG) is forecasted to be 8.9 BCF/day by the end of 2021.

The US power sector still represents the largest area of potential new gas demand, but increased usage is expected to be somewhat volatile as generation dispatch is sensitive to commodity price relationships and growth in renewable generation. Looking forward, economic dispatch competition is expected to continue between gas and coal, although forward natural gas prices have continued to decline and there has been permanent loss in overall coal generation due to the number of coal unit retirements.

In order to ensure adequate natural gas supplies, transportation and storage, the company has gas procurement strategies that include periodic Request for Proposals (RFPs), market solicitations, and short-term market engagement activities to procure a reliable, flexible, diverse, and competitively priced natural gas supply and transportation portfolio that supports DEP's generation facilities. With respect to storage and transportation needs, the company continues to add incremental firm pipeline capacity and gas storage as the gas generation fleet has grown. The company will continue to evaluate competitive options to meet its growing need for gas pipeline infrastructure as the gas generation fleet grows.

The Atlantic Coast Pipeline (ACP) project was an approximately 600-mile greenfield natural gas pipeline project originating in West Virginia with ultimate delivery into Piedmont's system in Robeson County, North Carolina providing pipeline diversity for the state of NC as well as pipeline diversity for the DEP and DEC electric systems. ACP had an initial capacity of 1.5 BCF/day and would have provided direct upstream access to natural gas production in the Marcellus and Utica shale basins of West Virginia, Pennsylvania and Ohio. On July 5<sup>th</sup>, 2020 Dominion Energy and Duke Energy announced the cancellation of ACP due to on-going legal uncertainty, anticipated delays and increasing cost uncertainty. DEP and DEC still need additional upstream firm interstate transportation service to support existing and future gas generation in the Carolinas despite the cancellation of the project. Given this change in planned interstate natural gas transportation infrastructure coming into the eastern part of NC, the 2020 IRP no longer includes direct access to interstate Marcellus and Utica shale basins coming into the eastern portions of NC.

To reliably and cost effectively support both the existing natural gas generation fleet and future combined cycle natural gas generation growth the 2020 IRP assumes incremental firm transportation service is obtained, as contemplated in the ACP project, with the exception of coming from alternate

pipeline providers. While such incremental firm transportation service may not produce the additional geographic pipeline transportation diversity of the original ACP project it will look to provide needed supply diversity, improve supply reliability and provide greater price stability for customers by reducing reliance on increasingly constrained delivered Transco Zone 5 natural gas supply. In this IRP, firm interstate transportation service is assumed to be procured for any new combined cycle natural gas resource selected in the generation portfolios in this plan along with estimates of the cost of this firm transportation service. The estimated firm transportation service costs were considered in the resource selection process and are included in the financial results presented.

Consistent with past IRPs, the planning process does not assume incremental interstate capacity is procured for additional simple cycle CTs given their low capacity factors. Rather, CTs are assumed to be constructed as dual fuel units that are ultimately connected to Transcontinental Pipeline (Transco) Zone 5. Simple cycle CTs will rely on delivered Zone 5 gas supply or, if needed, ultra-low sulfur fuel oil during winter periods where natural gas has limited availability, the pipeline has additional constraints, or if gas is higher priced than the cost to operate on fuel oil. The Company will continue to refine transportation volume and cost assumptions over time as future developments in interstate delivery options in the Carolinas are more fully known.

## COAL



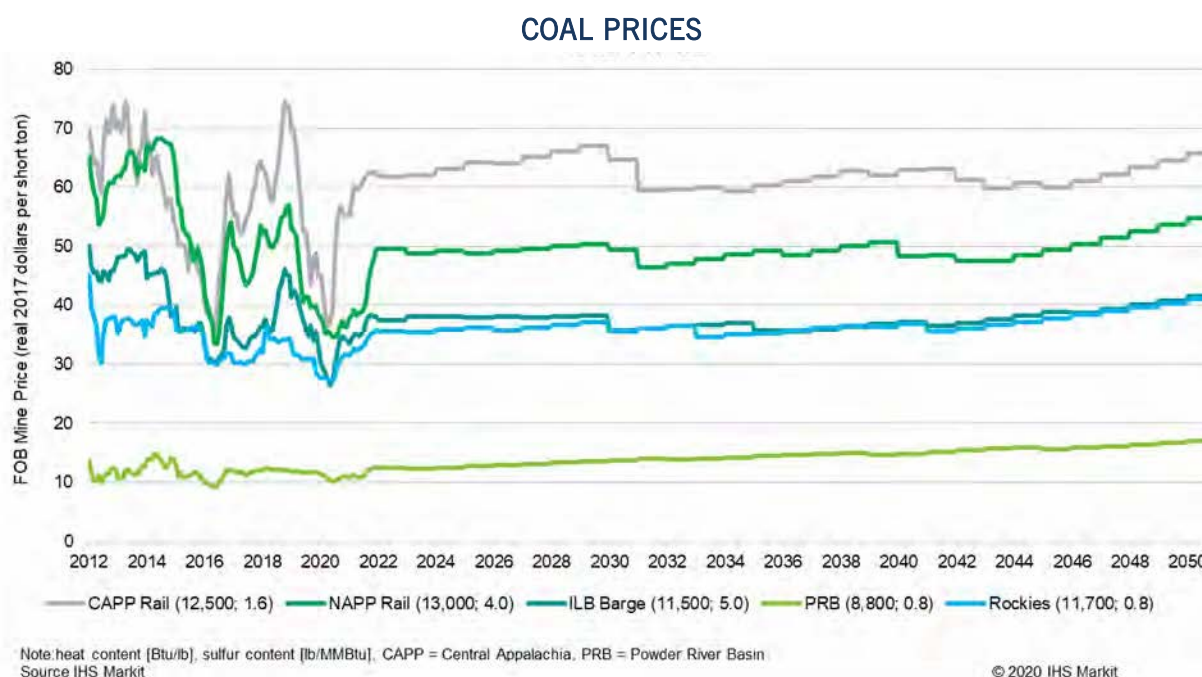
The main determinants for power sector coal demand are electricity demand growth and non-coal electric generation, namely nuclear, gas, hydro and renewables. With electricity demand growth remaining very low, continued steady nuclear and hydro generation, and increasing gas-fired and renewable generation, coal-fired generation continues to be the marginal fuel experiencing declines. According to the EIA, electric power sector demand has been steadily dropping and accounted for 539 million tons (90%) of total demand for coal in 2019. Additionally, projections show continued strong supply and fluctuating prices for natural gas which, when combined with the addition of new gas-fired combined cycle generating capacity continues to result in more volatile coal burns.

Coal markets continue to be distressed and there has been increased market volatility due to a number of factors, including: (1) deteriorated financial health of coal suppliers; (2) continued abundant natural gas supply and storage resulting in lower natural gas prices, which has lowered overall domestic coal demand; (3) uncertainty around proposed, imposed, and stayed U.S. Environmental

Protection Agency (EPA) regulations for power plants; (4) changing demand in global markets for both steam and metallurgical coal; (5) uncertainty surrounding regulations for mining operations; (6) tightening supply as bankruptcies, consolidations and company reorganizations have allowed coal suppliers to restructure and settle into new, lower on-going production levels.

According to IHS Markit, future coal prices for the Central Appalachian (CAPP), Northern Appalachian (NAPP), Illinois Basin (ILB) and Powder River Basin (PRB) coals are expected to be in a steady downward trend until 2020 when they see a modest rebound, flatten and begin to modestly and steadily rise. Future pricing for Rockies coal is expected to be steadily rise for the next 20 years.

**FIGURE F-2**  
**MINEMOUTH COAL PRICE FORWARD CURVE**



With the issuance of the Affordable Clean Energy (ACE) rule in 2019, the fundamental industry outlook now anticipates that less efficient higher cost coal unit retirements will accelerate, with only the lowest-cost production surviving long term. IHS Markit expects 80 GW of coal plant retirements from 2020 to 2025, followed by 42 GW from 2026 to 2030, and 68 GW from 2031 to 2050.

Coal exports have not been immune to global market pressures as total coal exports declined 20% in 2019 from historically high levels in 2018. IHS Markit expects US exports to be curtailed in the short-

term due to the economic impacts of COVID-19, but projects that exports, especially for metallurgical coal, should stabilize over the long-term horizon. Lower cost thermal export demand is projected to be mostly limited to NAPP and ILB longwall mine operations, while higher cost production mines are expected to struggle during weaker market years.

The Company continues to maintain a comprehensive coal procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost-effective manner. Aspects of this procurement strategy include having an appropriate mix of contract and spot purchases for coal, staggering coal contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts.

## NUCLEAR FUEL



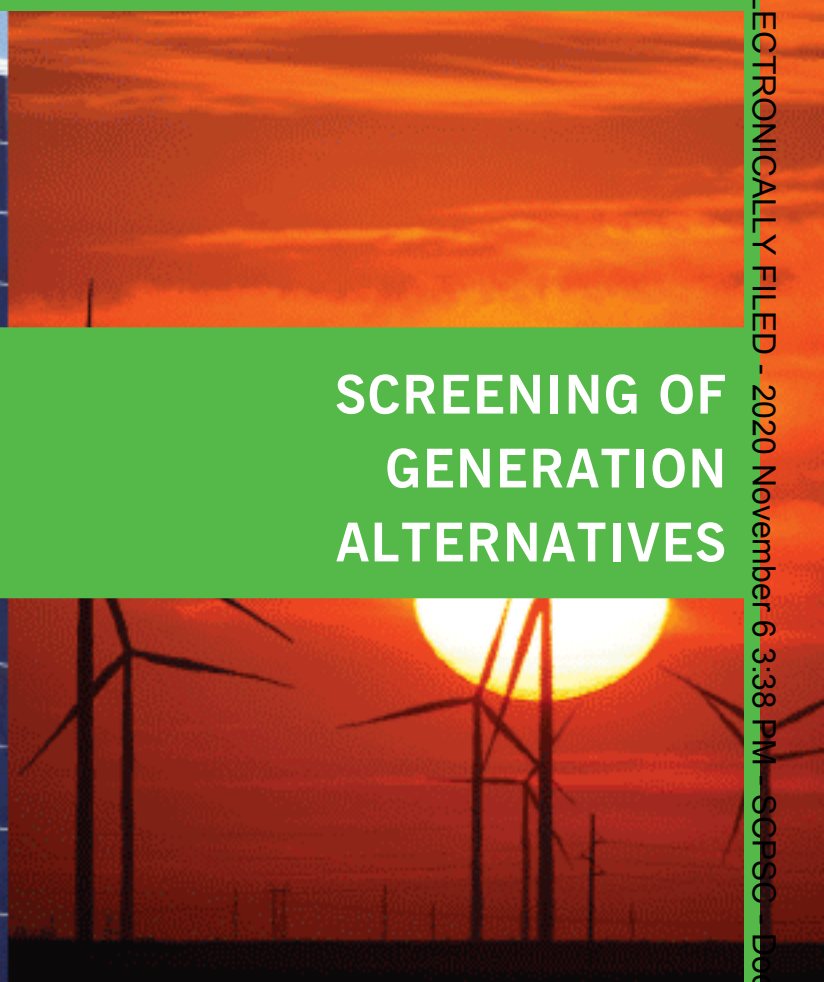
Requirements for uranium concentrates, conversion services and enrichment services are primarily met through a portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. In addition, DEP staggers its contracting so that its portfolio of long-term contracts covers the majority of fleet fuel requirements in the near-term and decreasing portions of the fuel requirements over time thereafter. By staggering long-term contracts over time, the Company's purchase price for deliveries within a given year consists of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with spot market purchases.

Due to the technical complexities of changing suppliers of fuel fabrication services, DEP generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts. As fuel with a low-cost basis is used and lower-priced legacy contracts are replaced with contracts at higher market prices, nuclear fuel expense is expected to increase in the future. Although the costs of certain components of nuclear fuel are expected to increase in future years, nuclear generation costs are expected to be competitive with alternate generation and customers will continue to benefit from the Company's diverse generation mix.





# SCREENING OF GENERATION ALTERNATIVES



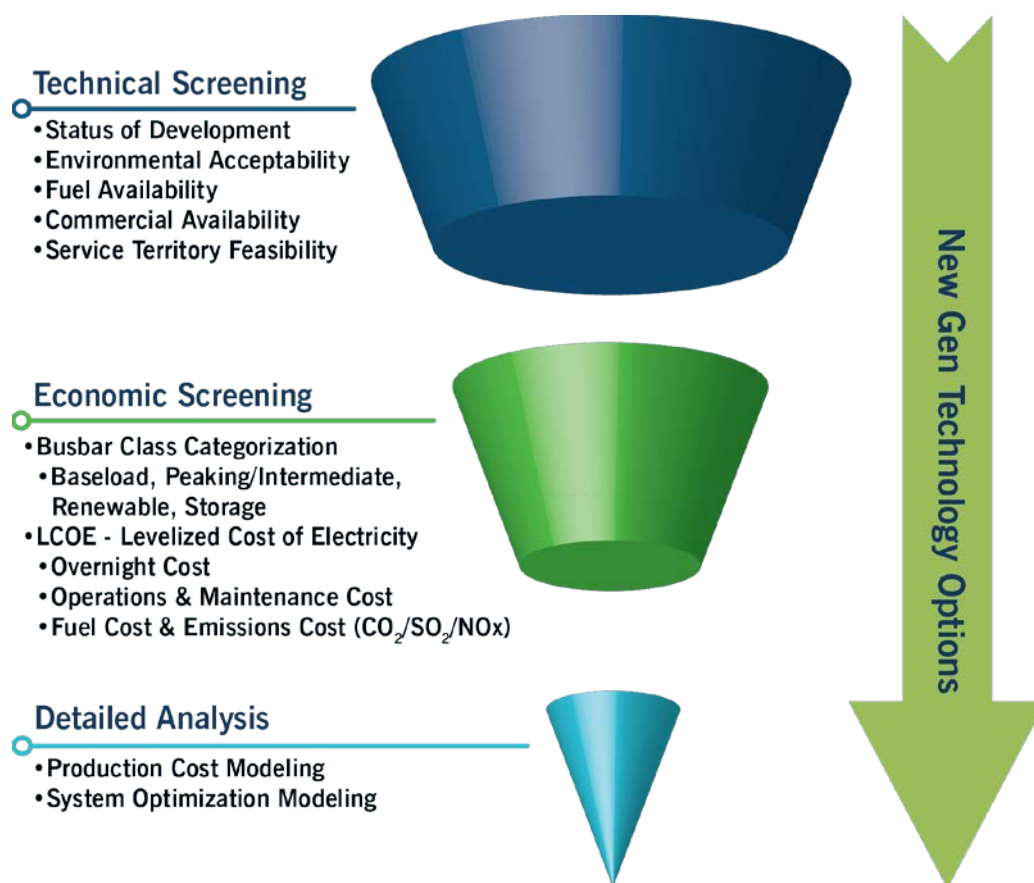


## APPENDIX G: SCREENING OF GENERATION ALTERNATIVES

The Company screens generation technologies prior to performing detailed analysis in order to develop a manageable set of possible generation alternatives. Generating technologies are screened from both a technical perspective as well as an economic perspective. In the technical screening, technology options are reviewed to determine technical limitations, commercial availability issues, and feasibility in the Duke Energy service territory.

Economic screening is performed using relative dollar per kilowatt-year (\$/kW-yr) versus capacity factor screening curves. The technologies must be technically and economically viable in order to be passed on to the detailed analysis phase of the IRP process.

**FIGURE G-1**  
**NEW GENERATION TECHNOLOGIES SCREENING PROCESS**



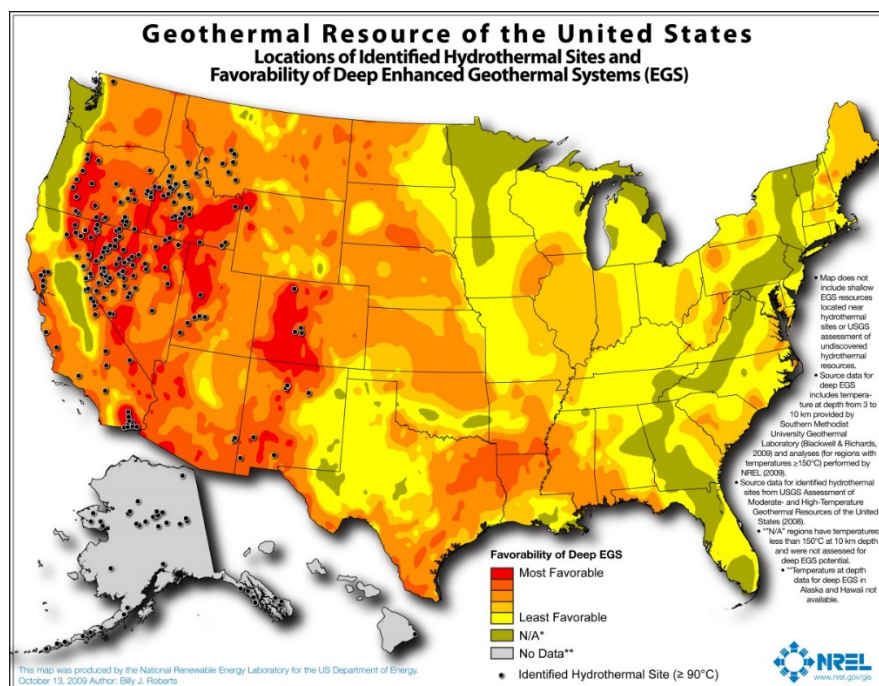
## TECHNICAL SCREENING

The first step in the Company's supply-side screening process for the IRP is a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the Duke Energy service territory. A brief explanation of the technologies excluded at this point and the basis for their exclusion follows:

**Fuel Cells**, although originally envisioned as being a competitor for combustion turbines and central power plants, are now targeted to mostly distributed power generation systems. The size of the distributed generation applications ranges from a few kW to tens of MW in the long-term. Cost and performance issues have generally limited their application to niche markets and/or subsidized installations. While a medium level of research and development continues, this technology is not commercially viable/available for utility-scale application. However, fuel cells have the potential to provide carbon-free energy if they utilize hydrogen as a fuel source and therefore continue to be reviewed to determine their applicability for future carbon reductions.

**Geothermal** was eliminated because there are no suitable geothermal resources in the region to develop into a power generation project – see Figure G-2, below. However, advanced geothermal is under development and is performing demonstration projects. Recent developments in deep direct-use geothermal may expand geothermal's applicability into some of the least favorable geological formations as seen in Figure G-2. Although these technologies have not yet reached commercial status, Duke Energy will continue to follow the technology as it may present geothermal energy capability within its service territory in the future.

NREL GEOTHERMAL RESOURCE MAP OF THE U.S.



**Small Modular Nuclear Reactors (SMR)** are generally defined as having a power output of less than 300 MW per reactor and utilizing water as the coolant. They typically have the capability of grouping a number of reactors in the same location to achieve the desired power generating capacity for a plant. In 2012, the U.S. Department of Energy (DOE) solicited bids for companies to participate in a small modular reactor grant program with the intent to “promote the accelerated commercialization of SMR technologies to help meet the nation’s economic energy security and climate change objectives.” SMRs continue to gain interest as they contribute no emissions to the atmosphere and, unlike their predecessors, provide flexible operating capabilities alongside inherently safer designs.

NuScale Power is the leader in SMR design and licensing in the US. A NuScale power module is expected to output 60 MW each, and a standard plant offering is expected to contain 12 modules. The NuScale design is expected to receive a certification from the Nuclear Regulatory Committee (NRC) in 2021, which would allow utilities to pursue the design as a new commercial asset. The first NuScale module is expected to reach commercial status in the late 2020s timeframe.

Two additional SMR designs are under development domestically including the GE Hitachi BWRX-300 and the Holtec SMR-160. The BWRX-300 design utilizes design features from the NRC-certified ESBWR, so although GE began their licensing process with the NRC after NuScale, they are expected to reach commercial availability in a similar timeframe. Holtec has not yet submitted a formal design certification request to the NRC and therefore there is no estimated commercialization timeframe in the US.

Similar to 2018, while SMRs were “screened out” in the Technical Screening phase of the technology evaluations due to commercial availability, they were allowed to be selected as a resource in the System Optimizer (SO) model in order to allow the model to meet the high CO<sub>2</sub> emission constraints in the sensitivity analysis. As a result, SMRs have been depicted on the busbar screening curves as an informative item. Duke Energy will be monitoring the progress of the SMR projects for potential consideration and evaluation for future resource plans as they provide an emission-free, diverse, flexible source of generation.

**Advanced Nuclear Reactors** are typically defined as nuclear power reactors employing fuel and/or coolant significantly different from that of current light water reactors (LWRs) and offering advantages related to safety, cost, proliferation resistance, waste management and/or fuel utilization. These reactors are characteristically typed by coolant with the main groups including liquid-metal cooled, gas cooled, and molten-salt fueled/cooled. There are at least 25 domestic companies working on one or multiple advanced reactor designs funded primarily by venture capital investment, and even more designs are being considered at universities and national labs across the country. There is also significant interest internationally with at least as many international companies pursuing their own advanced reactor designs in several countries across the world.

Specifics of the reactor vary significantly by both coolant type and individual designs. The reactors are projected to range in size from the single MW scale to over 1000 MW, with the majority of the designs proposing a modular approach that can scale capacity based on demand. Designs are typically exploring a flexible deployment approach which could scale power outputs to align with renewable/variable outputs. The first commercially available advanced reactors are targeting the late 2020s for deployment, although most designs are projected to be available in the 2030s. Significant legislative efforts are currently being made to further the development of advanced reactors in both the house and senate at the national level, and new bills continue to be introduced.

Duke Energy has been part of an overall industry effort to further the development of advanced reactors

since joining the Nuclear Energy Institute Advanced Reactor Working Group at its formation in early 2015. Additionally, Duke Energy participates on three Advanced Reactor companies' industry boards and has hosted several reactor developers for early design discussions. Duke Energy has also participated in other industry efforts such as EPRI's Owner-Operator Requirements Document, which outlines requirements and recommendations for Advanced Reactor designs. Duke Energy will continue to allot resources to follow the progress of the advanced reactor community and will provide input to the proper internal constituents as additional information becomes available.

**Poultry waste and swine waste digesters** remain relatively expensive and are often faced with operational and/or permitting challenges. Research, development, and demonstration continue, but these technologies remain generally too expensive or face obstacles that make them impractical energy choices outside of specific mandates calling for use of these technologies. See Appendix E for more information regarding current and planned Duke Energy poultry and swine waste projects.

**Solar Steam Augmentation** systems utilize solar thermal energy to supplement a Rankine steam cycle such as that in a fossil generating plant. The supplemental steam could be integrated into the steam cycle and support additional MW generation similar in concept to the purpose of duct firing a heat recovery steam generator. As the price of solar panels continues to drop, solar steam augmentation's economics compared to photovoltaic solar likely prevent this technology from moving forward. However, Duke Energy will continue to monitor developments in the area of steam augmentation.

**Supercritical CO<sub>2</sub> Brayton Cycle** is of increasing interest; however, the technology is still in the demonstration process. NET Power is the leading developer of the technology and is working on a pilot project. The early issues with the pilot show that the technology has not yet reached commercial status. Duke Energy will continue to monitor pilot and early commercial Supercritical CO<sub>2</sub> Brayton Cycle projects to determine if the technology passes the technical screening in future years.

**Hydrogen** as a fuel offers an advantage over traditional fossil fuels in not emitting carbon dioxide when burned. There has been substantial renewed interest by the industry in pursuing hydrogen as a replacement fuel for natural gas. Although promising, hydrogen as a utility fuel is still in the early stages from both a production and generation standpoint. Turbine manufacturers have proven successful with hydrogen/natural gas cofiring of up to 30% hydrogen by volume without significant gas turbine alterations in many of the combined cycle and combustion turbine plants currently in operation, dependent on gas turbine type. However, to move to 100% hydrogen-fueled turbines substantial improvements in turbine technology are required. Additionally, hydrogen production would

have to increase by many orders of magnitude to have ample supply to match the current production output of natural gas-fueled turbines. Duke Energy will continue to monitor hydrogen technology, both production and generation, to prepare for its potential future use as a natural gas fuel substitute.

**Additional Storage** technologies continue to be developed and pursued by a variety of companies. The range of technologies is vast and include non-lithium-ion batteries, mechanical storage, thermal storage, and variants of pumped hydro storage. Although some storage technologies passed the technology screening, the majority are still in a pre-commercial status. These technologies continued to be studied as future options for generation and include lead acid batteries, sodium-sulfur batteries, metal-air batteries, subterranean pumped storage, gravitational energy, hydrogen, flywheel energy, liquid air energy, chilled water, molten salt, silicon, concrete, sand, and phase change storage. Duke Energy will continue to monitor the developments and pilots of the various storage options to determine which designs have reached commercial status.

A brief explanation of the technology additions for 2020 compared to the 2018 Integrated Resource Plan submittal and the basis for their inclusion follows:

**Compressed Air Energy Storage (CAES)** offers an additional method of storage over longer durations than typically found in batteries. CAES is a proven, utility-scale energy storage technology that has been in operation globally for over 30 years. CAES has two primary application methods: diabatic and adiabatic. To utilize CAES, the project needs a suitable storage site, which is typically either a salt cavern or mined hard-rock cavern. Salt caverns have been preferred due to the low cavern construction costs. However, mined hard-rock caverns are now a viable option in areas that do not have salt formations with the use of hydrostatic compensation to increase energy storage density and reduce the cavern volume required. This change to allow mined hard-rock caverns created the potential for CAES in the Carolinas. CAES facilities use off-peak electricity to power a compressor train that compresses air into an underground reservoir. Energy is then recaptured by releasing the compressed air, heating it, and generating power as the heated air travels through an expander.

**Flow batteries** utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane in which the charge-inducing chemical reaction occurs, and liquid electrolyte storage tanks which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference.



The battery is charged as the liquid electrolytes are pumped through the electrode cell stacks, which serve only as a catalyst and transport medium to the ion-inducing chemical reaction. The excess positive ions at the anode are allowed through the ion-selective membrane to maintain electroneutrality at the cathode, which experiences a buildup of negative ions. The charged electrolyte solution is circulated back to storage tanks until the process is allowed to repeat in reverse for discharge as necessary.

In addition to external electrolyte storage, flow batteries differ from traditional batteries in that energy conversion occurs as a direct result of the reduction-oxidation reactions occurring in the electrolyte solution itself. The electrode is not a component of the electrochemical fuel and does not participate in the chemical reaction. Therefore, the electrodes are not subject to the same deterioration that depletes electrical performance of traditional batteries, resulting in high cycling life of the flow battery. Flow batteries are also scalable such that energy storage capacity is determined by the size of the electrolyte storage tanks, allowing the system to approach its theoretical energy density. Flow batteries are typically less capital intensive than some conventional batteries but require additional installation and operation costs associated with balance of plant equipment.

Although flow batteries' capital costs project to be higher than Li-Ion batteries, flow batteries project to become most effective as the duration of the battery is increased due to energy capacity being dictated primarily by the size of the tanks. Therefore, flow batteries have been included in the technology options as a longer duration storage option.

**Offshore Wind** is a developing technology in the United States but internationally has become a mature technology. Offshore wind farms have been installed in the oceans off European shores since the 1990s and continue to be an important source of energy in that market. There are several projects in various phases of development in U.S. coastal waters, and more are anticipated as technology and construction advancements allow for installation in deeper waters farther offshore. The Block Island project developed by Deepwater Wind is the first to reach commercial operation, and Duke Energy Renewables is performing remote monitoring and control services for the project. This 30 MW project is located about 3 miles off the coast of Rhode Island.

Duke Energy and NREL studied the potential for offshore integration off the coast of the Carolinas in March 2013. In 2015, the U.S. Bureau of Ocean Energy Management (BOEM) completed environmental assessments at three potential Outer Continental Shelf (OCS) sites off the coast of North Carolina. In March 2017, BOEM administered a competitive lease auction for wind energy in



federal waters and awarded Avangrid Renewables the rights to develop an area off the shores of Kitty Hawk. Avangrid has plans for a project that may be as large as 2,400 MW.

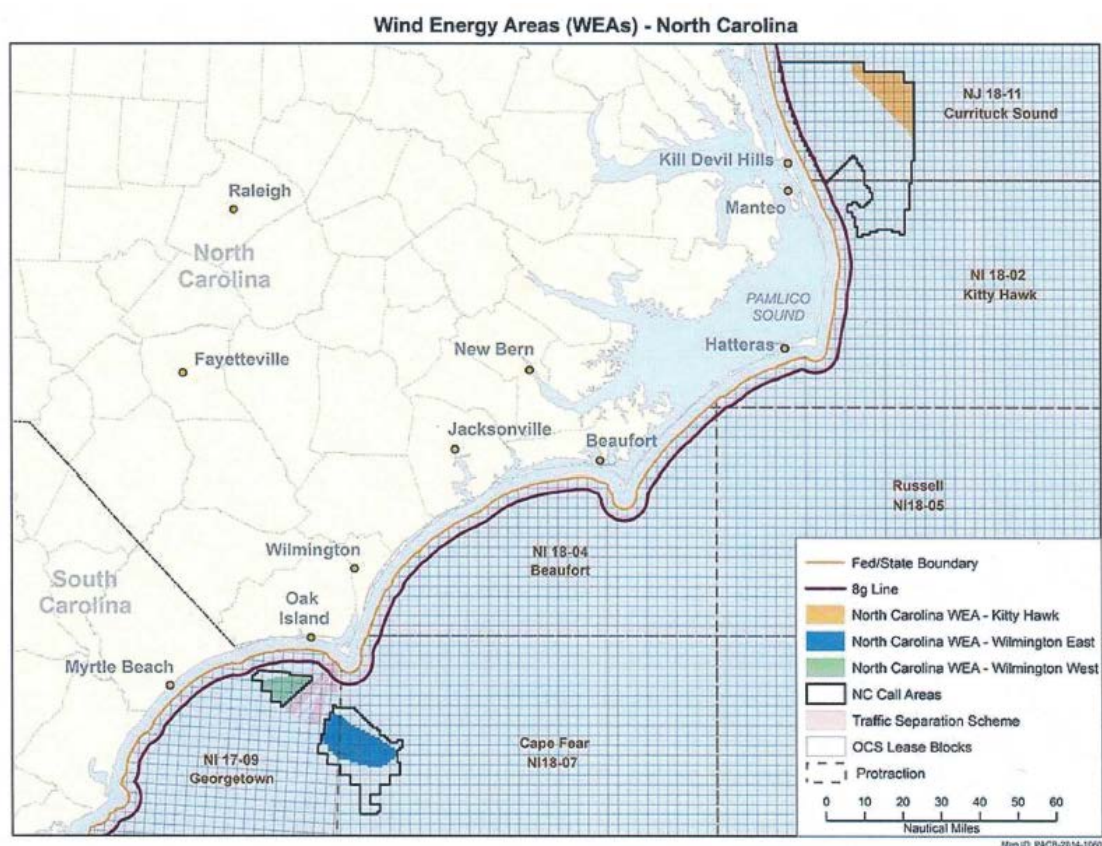
Several coastal states including New York, New Jersey, Maryland, Massachusetts, Connecticut, California, Rhode Island, Delaware, and Virginia have been forecasted to have projects developed. New York has an Offshore Wind Master Plan aimed at 2,400 MW of offshore projects by 2030, and Statoil is developing the 1,500 MW Empire Wind project near New York City, aiming for completion in 2025.

The unique constraints of the industry and the increasingly competitive global market are driving R&D improvements that allow wind farms to be sited farther offshore. Installation and siting require careful consideration to bathymetry and offshore construction concerns, but siting is further complicated by shipping lanes, fishing rights, wildlife migration patterns, military operations, and other environmental concerns. Plus, coastal residents and tourists prefer an unobstructed ocean view, so the larger turbines require longer distances to keep them out of sight.

Although technology costs still remain high for offshore wind, the technology is being evaluated as an additional renewable option. The profile of offshore wind allows for a higher capacity factor in the Carolinas than onshore wind, and the profile also compliments solar energy.

FIGURE G-3

## NC WIND ENERGY AREAS (WEAS) (DEVELOPED IN JOINT VENTURE BY DUKE ENERGY AND NREL)



## GENERATION FLEXIBILITY AND DUKE ENERGY CLIMATE PLAN

As more intermittent generation becomes associated with Duke's system there is a greater need for generation that has rapid load shifting and ancillary support capabilities. This generation would need to be dispatchable, possess desirable capacity, and ramp at a desired rate. Some of the technologies that have 'technically' screened in possess these qualities or may do so in the near future. Effort is being made to value the characteristics of flexibility and quantify that value to the system. As a result of the flexible generation need, some features of 'generic' plant's base designs have been modified to reflect the change in cost and performance to accomplish a more desired plant characteristic to diminish the impact of the intermittent generation additions.

Additionally, in 2020 Duke Energy released a revision to its previous Climate Report with aggressive goals to reduce output from its generating facilities by 2030 and even deeper reductions by 2050. Duke Energy concluded that it would need new technologies that have not yet reached commercialization status that performed as Zero-Emitting Load-Following Resources (ZELFR). The load-following requirement comes from the flexibility need described above, and the zero-emission portion is to help Duke Energy meet its future climate goals.

Duke Energy is evaluating several generation technologies that are considered pre-commercial to meet the ZELFR need. Technologies considered typically fall under the broad categories of advanced nuclear, advanced renewables, advanced transmission and distribution, biofuels, carbon capture utilization and sequestration, fuel cells, hydrogen, long duration energy storage, and supercritical CO<sub>2</sub> Brayton Cycle. All of these technologies are expected to help Duke Energy meet future carbon reduction goals if they reach commercial status and are economically competitive.

Duke Energy expects multiple technologies to be required to meet its carbon reduction goals, and therefore Duke Energy is considering potential paths to help move these technologies towards commercialization. One such effort Duke Energy is pursuing is the recently announced partnership with two advanced reactor developers on DOE's Advanced Reactor Deployment Program to deploy one of the first two advanced nuclear reactors. Another effort underway is the collaborative work with Siemens as part of DOE's Energy Storage for Fossil Generation Program to evaluate the possibility of hydrogen co-firing at the Combined Heat and Power Plant on Clemson's campus. Duke Energy recognizes the potentially long commercialization timeframe for some of these technologies and will continue to pursue efforts to move these important technologies forward.

Although these technologies all screen out in the process due to their commercial status, Duke Energy will continue to follow a wider range of technologies to meet these future generation needs.

## ECONOMIC SCREENING

The Company screens all technologies using relative dollar per kilowatt-year (\$/kW-yr) versus capacity factor screening curves, also referred to as *busbar* curves. By definition, the *Busbar* curve estimates the revenue requirement (i.e. life-cycle cost) of power from a supply option at the "busbar," the point at which electricity leaves the plant (i.e. the high side of the step-up transformer). Duke Energy provides some

additional evaluation of a generic transmission and/or interconnection cost adder associated with each technology.

The screening within each general class of busbar (Baseload, Peaking/Intermediate, Renewables and Storage), as well as the final screening across the general classes, uses a spreadsheet-based screening curve model developed by Duke Energy. This model is considered proprietary, confidential and competitive information by Duke Energy. Again, for the 2020 IRP year, Duke Energy has provided an additional set of busbar curves to represent Storage technology comparisons. As Storage technologies are not traditional generating resource options, they should be compared independently from generating resources. In addition, there has been no *charging* cost associated with the storage busbar buildup. This charging cost is excluded as it is dependent upon what the next marginal unit is in the dispatch stack as to what would be utilized to "charge" the storage resource. For resource options inclusive of or coupled with storage, it is assumed that the storage resource is being directly charged by the generating resource (i.e. Solar PV plus Battery Storage option).

This screening (busbar) curve analysis model includes the total costs associated with owning and maintaining a technology type over its lifetime and computes a levelized \$/kW-year value over a range of capacity factors. The Company repeats this process for each supply technology to be screened resulting in a family of lines (curves). The lower envelope along the curves represents the least costly supply options for various capacity factors or unit utilizations. Some technologies have screening curves limited to their expected operating range on the individual graphs. Lines that never become part of the lower envelope, or those that become part of the lower envelope only at capacity factors outside of their relevant operating ranges, have a very low probability of being part of the least cost solution, and generally can be eliminated from further analysis.

The Company selected the technologies listed below for the screening curve analysis. While future carbon emission constraints may effectively preclude new coal-fired generation, Duke Energy has included ultra-supercritical pulverized coal (USCPC) with carbon capture sequestration (CCS) and integrated gasification combined cycle (IGCC) technologies with CCS of 1400 pounds/net MWh capture rate as options for baseload analysis. 2020 additions include Offshore wind, additional Lithium Ion Battery Storage options, Flow Battery Storage, and Advanced Compressed Air Energy Storage.





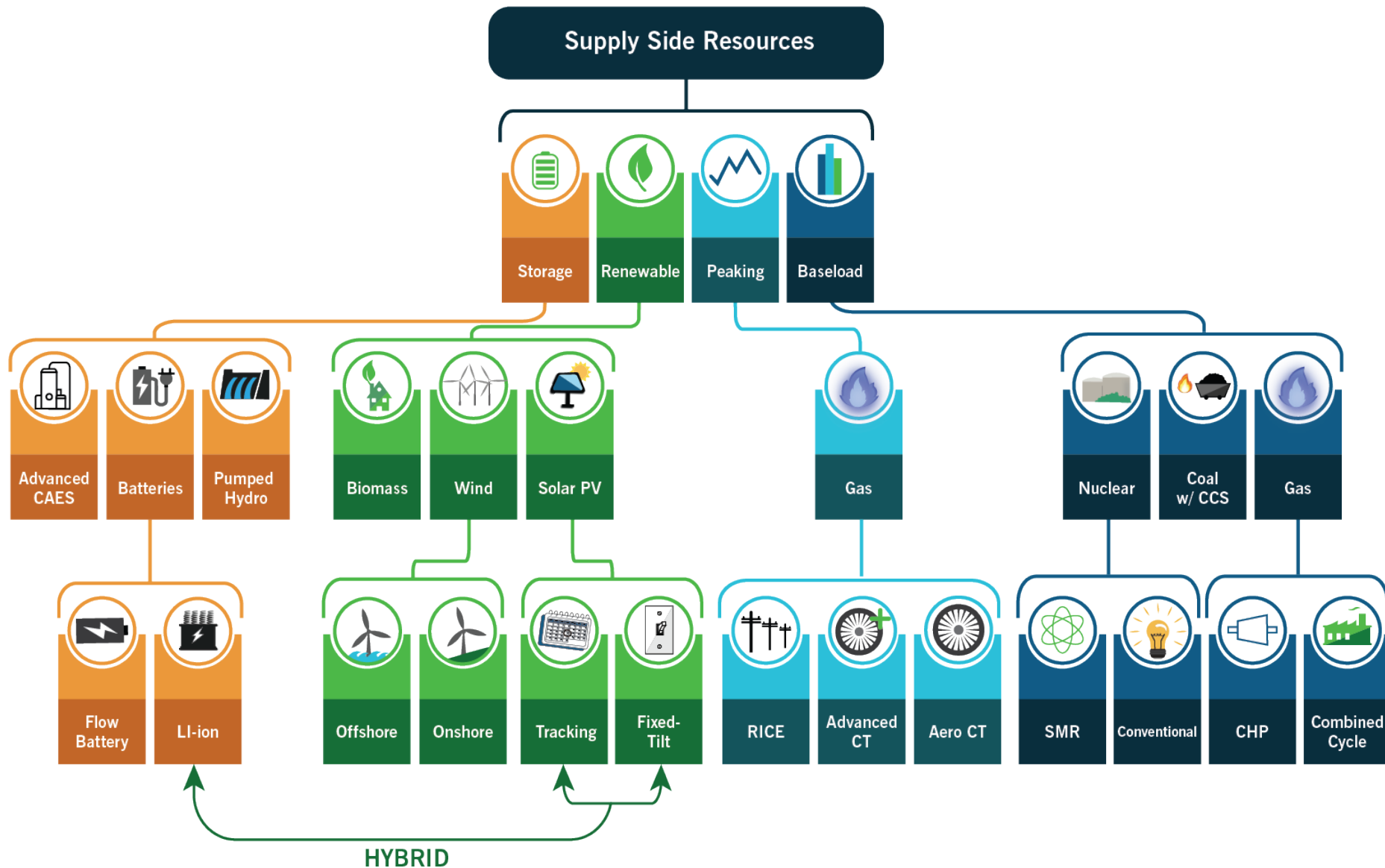
DISPATCHABLE (WINTER RATINGS)			
			
BASELOAD	PEAKING / INTERMEDIATE	STORAGE	RENEWABLE
601 MW, 1x1x1 Advanced Combined Cycle (No Inlet Chiller and Fired)	18 MW, 2 x Reciprocating Engine Plant	10 MW / 10 MWh Lithium-ion Battery	75 MW Wood Bubbling Fluidized Bed (BFB, biomass)
1,224 MW, 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)	15 MW Industrial Frame Combustion Turbine (CT)	10 MW / 20 MWh Lithium-ion Battery	5 MW Landfill Gas
782 MW Ultra-Supercritical Pulverized Coal with CCS	192 MW, 4 x LM6000 Combustion Turbines (CTs)	10 MW / 40 MWh Lithium-ion Battery	NON- DISPATCHABLE (WINTER RATINGS)
557 MW, 2x1 IGCC with CCS	201 MW, 12 x Reciprocating Engine Plant	50 MW / 200 MWh Lithium-ion Battery	
720 MW, 12 Small Modular Reactor Nuclear Units (NuScale)	752 MW, 2 x J-Class Combustion Turbines (CTs)	50 MW / 300 MWh Lithium-ion Battery	600 MW Offshore Wind
2,234 MW, 2 Nuclear Units (AP1000)	913 MW, 4 x 7FA.05 Combustion Turbines (CTs)	20 MW / 160 MWh Redox Flow Battery	75 MW Fixed-Tilt (FT) Solar PV
9 MW Combined Heat & Power (Reciprocating Engine)		250 MW / 4,000 MWh Advanced Compressed Air Energy Storage	75 MW Single Axis Tracking (SAT) Solar PV
21 MW – Combined Heat & Power (Combustion Turbine)		1,400 MW Pumped Storage Hydro (PSH)	75 MW SAT Solar PV plus 20 MW / 80 MWh Lithium-ion Battery

FIGURE G-4

DUKE ENERGY, SCREENED-IN SUPPLY SIDE RESOURCE ALTERNATIVES



Corrected 11.06.2020



## INFORMATION SOURCES

The cost and performance data for each technology being screened is based on research and information from several sources. These sources include a variety of internal departments at Duke Energy. In addition to the internal expertise, the following external sources may also be utilized: proprietary third-party engineering studies, the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG®), and Energy Information Administration (EIA). In addition, fuel and operating cost estimates are developed internally by Duke Energy, or from other sources such as those mentioned above, or a combination of the two. EPRI information or other information or estimates from external studies are not site-specific but generally reflect the costs and operating parameters for installation in the Carolinas. Finally, every effort is made to ensure that capital, operating and maintenance costs (O&M), fuel costs and other parameters are current and include similar scope across the technologies being screened. The supply-side screening analysis uses the same fuel prices for coal and natural gas, and NO<sub>x</sub>, SO<sub>2</sub>, and CO<sub>2</sub> allowance prices as those utilized downstream in the detailed analysis (discussed in Appendix A). Screening curves were developed for each technology to show the economics with and without carbon costs (i.e. No CO<sub>2</sub>, With CO<sub>2</sub>) in the four major categories defined (Baseload, Peaking/Intermediate, Renewables, Storage).

## CAPITAL COST FORECAST

A capital cost forecast was developed with support from a third party to project not only Renewables and Battery Storage capital costs but the costs of all resource technologies technically screened in. The Technology Forecast Factors were sourced from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2020 which provides cost projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS) utilized by the EIA for the AEO.

Using 2020 as a base year, an "annual cost factor is calculated based on the change from a base year for the macroeconomic variable tracking the metals and metal products producer price index, thereby creating a link between construction costs and commodity prices." (NEMS Model Documentation 2018, April 2019)



From NEMS Model Documentation 2018, April 2019:

*“Uncertainty about investment costs for new technologies is captured in the ECP [Electricity Planning Submodule] using technological optimism and learning factors. The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate and the technological optimism factor declines.*

*Learning factors represent reductions in capital costs as a result of learning-by-doing. Learning factors are calculated separately for each of the major design components of the technology. Generally, overnight costs for new, untested components are assumed to decrease by a technology specific percentage for each doubling of capacity for the first three doublings, by 10% for each of the next five doublings of capacity, and by 1% for each further doubling of capacity. For mature components or conventional designs, costs decrease by 1% for each doubling of capacity.”*

The resulting Forecast Factor Table developed from the EIA technology maturity curves for each corresponding technology screened is depicted in Table G-1.

**TABLE G-1**  
**SNAPSHOT FROM FORECAST FACTOR TABLE BY TECHNOLOGY (EIA -**  
**AE0 2020)**

YEAR	FRAME CT	AERO CT	NUCLEAR	BATTERY STORAGE	1X1 COMBINED CYCLE	ONSHORE WIND
2020	1.000	1.000	1.000	1.000	1.000	1.000
2021	0.985	0.987	0.984	0.812	0.987	0.987
2022	0.970	0.973	0.967	0.718	0.973	0.973
2023	0.950	0.961	0.950	0.640	0.961	0.961
2024	0.901	0.953	0.920	0.625	0.953	0.953
2025	0.873	0.945	0.909	0.609	0.945	0.945
2026	0.852	0.937	0.898	0.594	0.937	0.937
2027	0.831	0.928	0.886	0.579	0.927	0.928
2028	0.815	0.918	0.874	0.563	0.918	0.918
2029	0.803	0.907	0.861	0.546	0.907	0.907
2030	0.789	0.896	0.847	0.530	0.896	0.896

## SCREENING RESULTS

The results of the screening within each category are shown in the figures below. Results of the baseload screening show that natural gas combined cycle generation is the least-cost baseload resource. With lower gas prices, larger capacities and increased efficiency, natural gas combined cycle units have become more cost-effective at higher capacity factors in all carbon scenario screening cases (i.e. No CO<sub>2</sub> and With CO<sub>2</sub>). Although CHP can be competitive with CC, it is site specific and requires a local steam and electrical load. Carbon capture systems have been demonstrated to reduce coal-fired CO<sub>2</sub> emissions to levels similar to natural gas and will continue to be monitored as they mature; however, their current cost and uncertainty of safe, reliable storage options has limited the technical viability of this technology in Duke Energy territories.

The peaking technology screening included F-frame and J-Frame combustion turbines, fast start aero-derivative combustion turbines, and fast start reciprocating engines. The screening curves show the F-frame CTs to be the most economic peaking resource unless there is a special application that requires

the fast start capability of the aero-derivative CTs or reciprocating engines. Reciprocating engine plants offer the lowest heat rates and fastest start times among simple cycle options. Simple cycle aeroderivative gas turbines remain in close contention with reciprocating engines. Should a need be identified for one of these two types of resources, a more in-depth analysis would be performed.

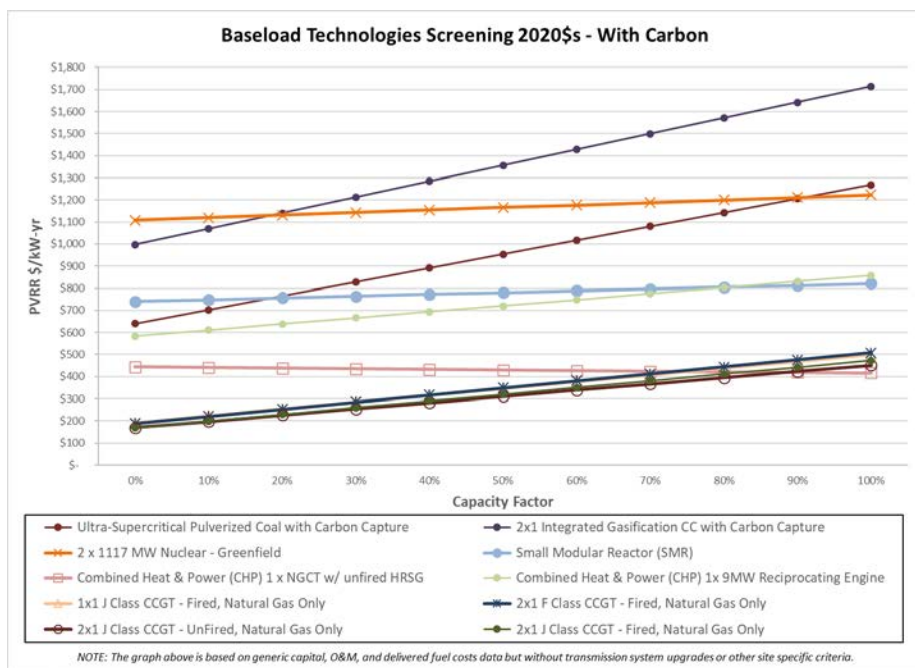
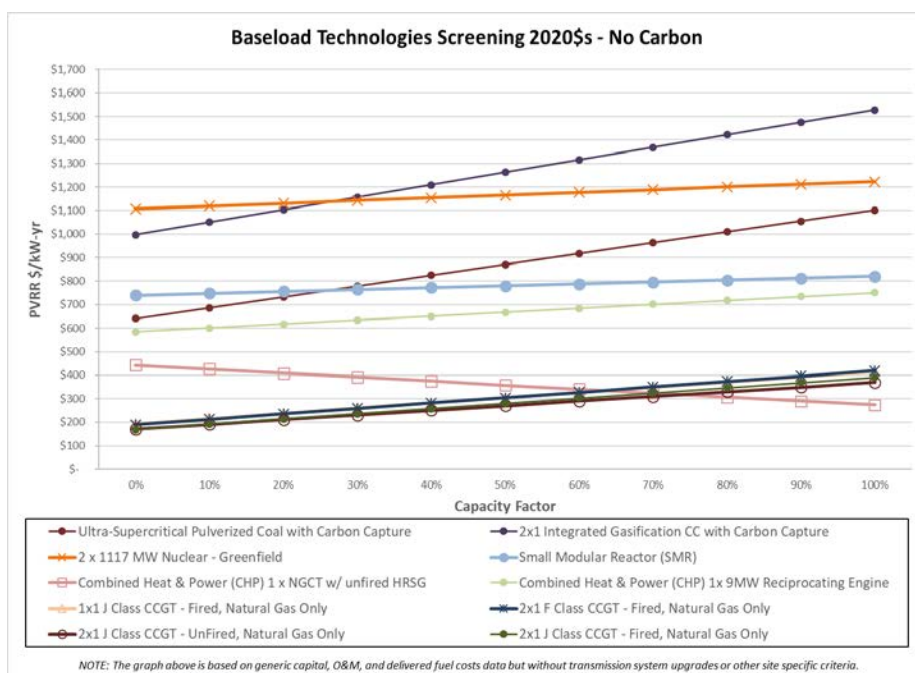
The renewable screening curves show solar continues to be a more economical alternative than other renewable resource options. Solar and wind projects are technically constrained from achieving high capacity factors making them unsuitable for intermediate or baseload duty cycles. Landfill gas and biomass projects are limited based on site availability but are dispatchable. Landfill gas is not shown in the busbar curve for renewables as the options are limited since most sites have already been transacted with. Although solar PV prices have become competitive with conventional generators, the lack of dispatchability and low capacity factor does not allow it to be a baseload resource.

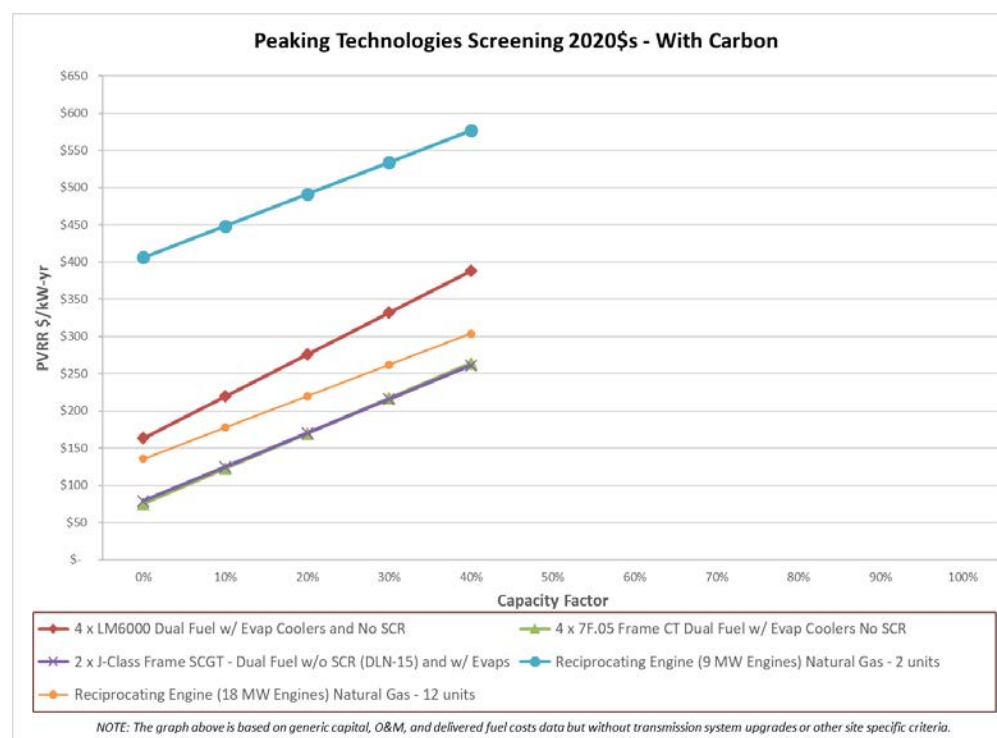
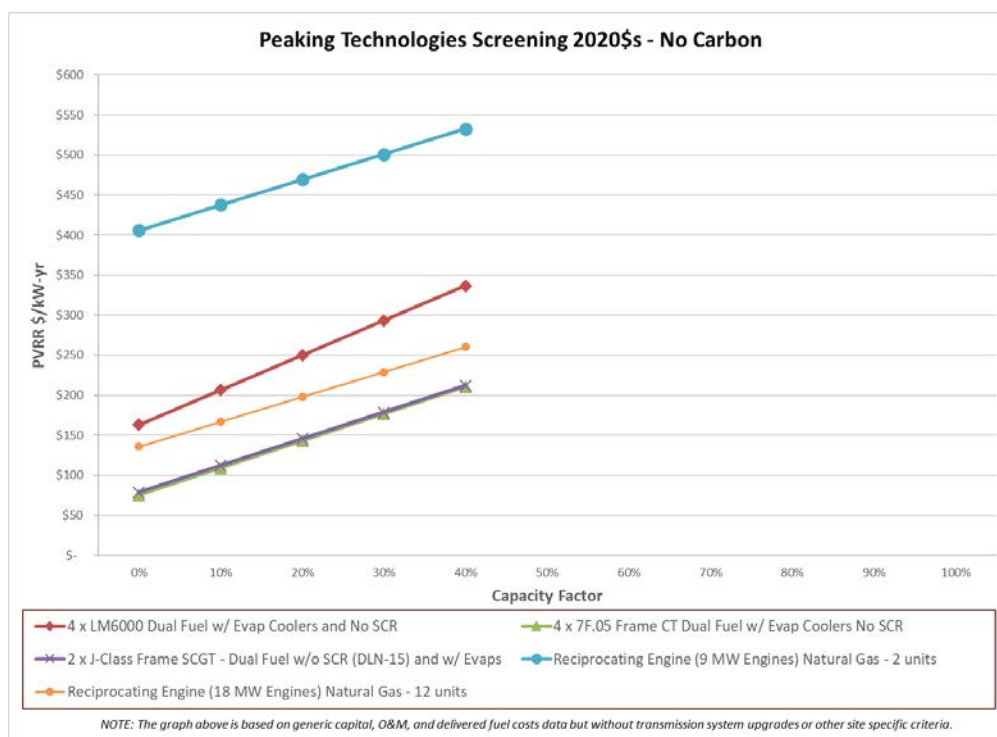
Energy storage has become an increasingly important asset as companies add more variable resources to their portfolio. Energy storage can provide a variety of benefits to the grid and overall resource portfolio. Additional information on energy storage can be found in Appendix H. For the screening results, the lowest \$/kW option for energy storage was 1-hour duration Li-Ion storage as expected. However, batteries have a variety of use cases and longer duration storage can be more useful than shorter duration storage in certain cases. Additionally, the \$/kWh decreases as the duration of the storage increases. So, although the 1-hour duration Li-Ion battery storage asset had the lowest screening cost, the specific application of the storage option will determine which storage option is the best fit for its use case.

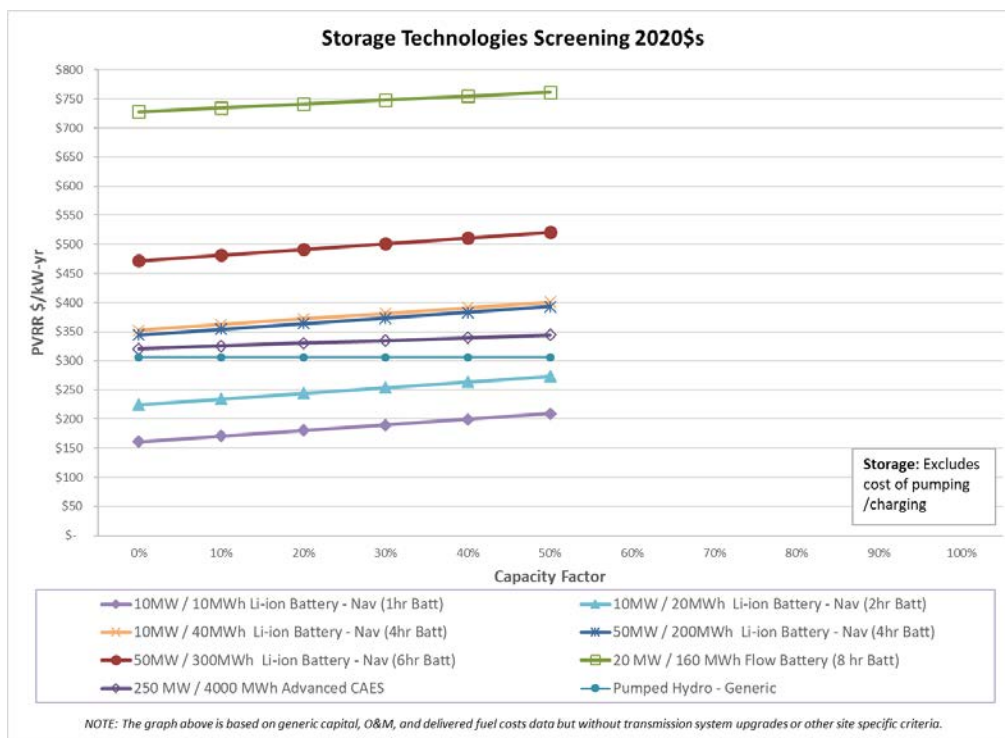
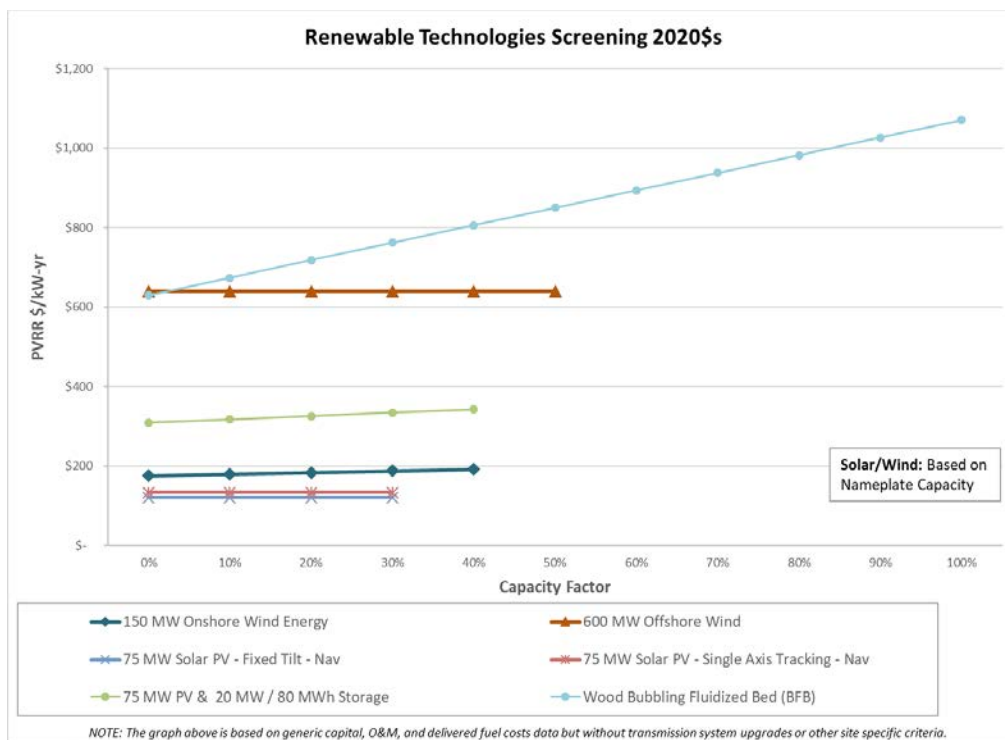
The screening curves are useful for comparing costs of resource types at various capacity factors but cannot be solely utilized for determining a long-term resource plan because future units must be optimized with an existing system containing various resource types. Results from the screening curve analysis provide guidance for the technologies to be further considered in the more detailed quantitative analysis phase of the planning process.

## SCREENING CURVES

The following pages contains the technology screening curves for baseload, peaking/intermediate, renewable and storage technologies.











# H

## ENERGY STORAGE





## APPENDIX H: ENERGY STORAGE

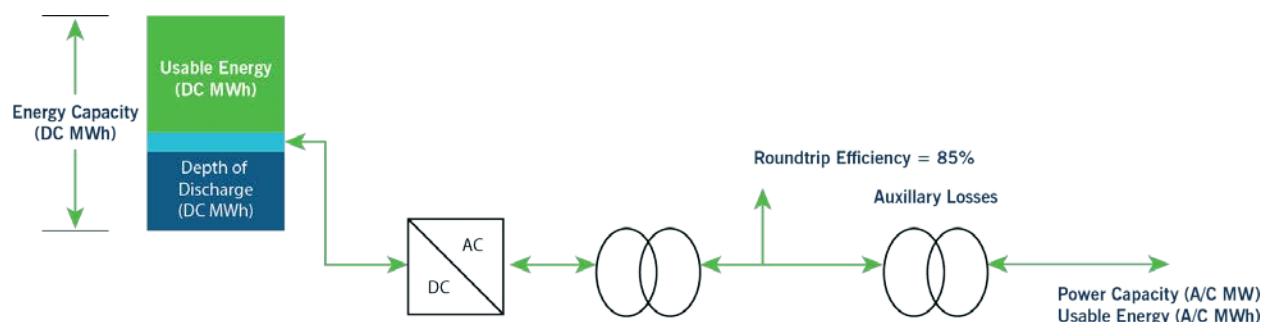
Battery storage is expected to play an important role in meeting future needs on the DEP system. As discussed in Chapter 6, battery storage can provide multiple services. For purposes of the 2020 IRP, the Company considered capacity, energy arbitrage, and ancillary service benefits when valuing battery storage. Additionally, the Company conducted a thorough review of battery cost and operating assumptions modeled in the 2020 IRP. Benchmarking battery storage costs across publications is difficult, and oftentimes not possible, due to disparate definitions and incomplete documentation. Some publications do not include the full cost that would be needed to construct a battery storage system that would meet the requirements of a manufacturer's warranty and the needs of the Utility over the life of the asset. For this reason and to provide transparency of the cost estimating process, the Company is detailing the battery storage assumptions used in the 2020 IRP below.

Finally, in order to appropriately estimate the capacity value battery storage can provide, the Company hired a third-party consultant to conduct an Effective Load Carrying Capability (ELCC) study to quantify the contribution to winter peak demand that battery storage could provide in DEP. The results of the ELCC study are described in the following sections and the Battery Storage ELCC study has been filed along with the IRP filing.

### BATTERY STORAGE TERMINOLOGY AND OPERATING ASSUMPTIONS

Some of the terminology that the Company uses to describe batteries in the IRP is detailed below. Importantly, while many of the terms and definitions below are standard across the industry, some of the terms are specific to how battery storage is described in this IRP and may not match what is described in other publications. Where appropriate, definitions that are taken directly from outside publications are cited. The following is a diagram of a standalone battery storage system that is modeled in the 2020 IRP.

FIGURE H-1  
SIMPLIFIED BATTERY STORAGE SYSTEM MODELED IN 2020 DEP IRP



- Battery size** – Battery sizing is generally provided in capacity and energy values or capacity value and duration. The terms “capacity”, “energy”, and “duration” are discussed below. An example of battery size nomenclature is “50 MW / 200 MWh” which represents a 50 MW battery with a 4-hour duration.
- Capacity** – Generally referred to as “power capacity” in the industry and represents the total possible instantaneous discharge capability of the battery storage system, or the maximum rate of discharge the battery can achieve starting from a fully charged state.<sup>1</sup> The Company measures power capacity at the point of interconnect to the transmission system and the units are “MW AC.” The IRP represents the cost of a battery in \$/MW where the numerator, or dollars, is the total cost of the battery system and the denominator is the power capacity in MW AC of the system. The components of the total cost of the battery system are described in further detail below.
- Energy** – The energy that a battery can hold can be represented differently between publications which can make comparing costs between sources of data difficult. For the purposes of this IRP, the Company considers energy in the following manners:
  - Usable Energy** – Refers to the amount of energy that can be discharged at the point of interconnection over the duration of the battery. Usable energy can be described in units of “MWh AC” or “MWh DC.” When the Company discusses the cost of a

<sup>1</sup> <https://www.nrel.gov/docs/fy19osti/74426.pdf>.

battery on a \$/MWh basis, the numerator is the total cost of the battery system and the denominator is the usable energy in units of MWh AC.

- Depth of Discharge (DoD)** – “Indicates the percentage of the battery that has been discharged relative to the overall [energy] capacity of the battery.”<sup>2</sup> In the 2020 IRP, this number represents the amount of energy that must remain, unused, in the battery to satisfy the warranty of the battery and/or allow the battery to complete the expected number of cycles over the life of the asset. For instance, the Company uses a 20% depth of discharge limit which simply means the battery cannot discharge more than 80% of its energy capacity. Some publications only provide battery costs based on the usable energy of the battery thereby ignoring the DoD; however, the Company calculates the cost of a battery based on the energy capacity, which includes the DoD limitation.
- Energy Capacity** – The total amount of energy that can be stored or discharged by the battery storage system.<sup>3</sup> In the diagram above, energy capacity is the sum of the usable energy and the depth of discharge limit. Energy capacity is defined in units of “MWh DC.” The Company did not include additional costs for other “unused” energy required to maintain the contracted usable energy of the battery, such as additional energy capacity to account for DC or AC losses that occur during charge and discharge of the battery. However, within the production cost model, the Company does account for the production cost impacts of losses on roundtrip efficiency of the battery as discussed below.
- Duration** – “Amount of time storage can discharge at its power capacity.”<sup>4</sup> For example, a battery with 50 MW of power capacity and 200 MWh of usable energy capacity will have a storage duration of 4 hours.
- Roundtrip Efficiency** – “Measured as a percentage, is a ratio of the energy charged to the battery to the energy discharged from the battery. It can represent the total DC-DC or AC-AC efficiency of the battery system, including losses from self-discharge and other electrical

<sup>2</sup> <https://news.energysage.com/depth-discharge-dod-mean-battery-important/#:~:text=A%20battery's%20depth%20of%20discharge,DoD%20is%20approximately%2096%20percent.>

<sup>3</sup> U.S. Battery Storage Trends, U.S. Energy Information Administration, May 2018

<sup>4</sup> <https://www.nrel.gov/docs/fy19osti/74426.pdf>

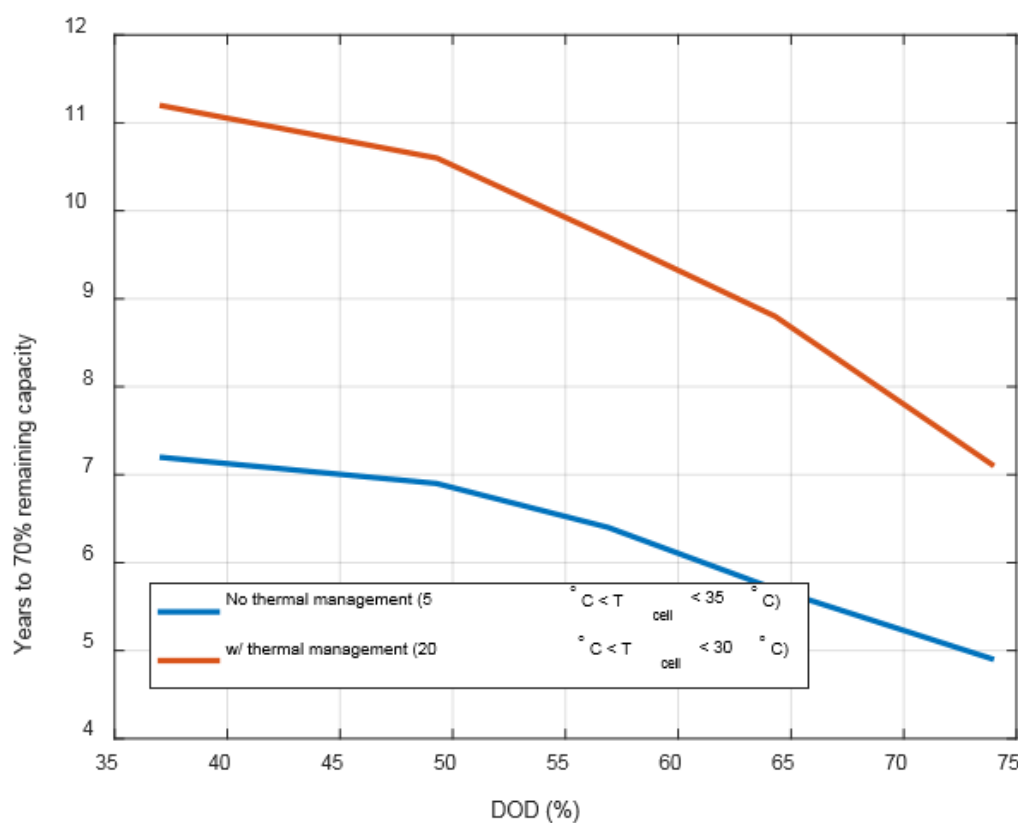
losses.”<sup>5</sup> The Company uses A/C - A/C efficiency as the production cost models only consider the charging/discharging at the point of interconnect to the power system. The Company assumed a roundtrip efficiency of 85% for all lithium-ion (Li-ion) batteries modeled in the 2020 IRP.

- **Auxiliary Losses** - Included as part of other electrical losses in the calculation of round-trip efficiency and can include power required for HVAC systems associated with the battery storage system.
- **Degradation** – The loss of energy capacity of a battery storage system overtime. “Degradation of lithium-ion batteries is impacted by several variables. Known drivers of degradation include: temperature of operation, average state of charge over its lifetime, and depth of charge-discharge cycles.”<sup>6</sup> Figure 2, sourced from NREL’s “Life Prediction Model for Grid Connected Li-ion Battery Energy Storage System” demonstrates the effects that DoD and temperature management of the battery storage system can have on degradation.

<sup>5</sup> <https://www.nrel.gov/docs/fy19osti/74426.pdf>

<sup>6</sup> <https://www.energy-storage.news/blogs/is-that-battery-cycle-worth-it-maximising-energy-storage-lifecycle-value-wi#:~:text=Battery%20storage%20degradation%20typically%20manifests,need%20for%20replacement%20of%20batteries.>

**FIGURE H-2**  
**IMPACT OF BATTERY OVERSIZING AND THERMAL MANAGEMENT ON**  
**LIFETIME FROM NREL <sup>7</sup>**



- Battery Augmentation** – As a battery storage system experiences degradation, battery cells can be replenished on a regular, or semi-regular, basis to maintain the usable energy of the battery storage system. This strategy to counteract degradation leads to lower initial capital costs but incurs higher on-going costs throughout the life of the asset. For IRP purposes, the Company assumes a Battery Augmentation strategy to minimize total costs over the 15-year assumed life of the battery asset, while recognizing that this approach does present some challenges with maintaining stable performance of the system.
- Overbuild** – Refers to an increase in the nameplate energy capacity to account for expected degradation. As an alternative strategy to augmentation, the battery storage system can

<sup>7</sup> <https://www.nrel.gov/docs/fy17osti/67102.pdf>.

initially be physically oversized beyond depth of discharge limits to account for degradation. This strategy yields higher initial capital costs but lower on-going costs versus an augmentation strategy.

## BATTERY STORAGE COST ASSUMPTIONS

Battery storage costs have been declining rapidly over the last several years, and they are expected to continue declining for the foreseeable future. In fact, the Company assumes that battery prices will drop by nearly 50% over the next 9 years.<sup>8</sup>

The Company's capital cost assumptions are developed by a third party and are benchmarked against both internal and external sources. Often, the Company's prices appear higher than published numbers. As discussed above, there are several factors that can drive this difference including:

- The Company calculates the cost of a battery storage device assuming a 20% DoD limit while other publications likely only calculate the cost of the battery based on the rated energy of the battery from their information sources, which often do not specify whether their energy rating factors in DoD. In cases where the energy rating does not account for DoD, the cost of the battery can differ by over 10%.
- The Company assumes interconnection costs based on historical costs on the DEP system. Other publications may include lower interconnection costs or may not account for interconnection costs altogether.
- Because the Company expects to rely on these assets for at least 15-years to provide reliable capacity and energy to its customers on a real-time basis, some of the Company's assumptions of software and controls may lead to higher capital costs than a device that is designed to provide capacity and energy with lower reliability standards or on a more standard schedule.
- Similarly, the Company may be including more expensive HVAC and fire detection and suppression assumptions when calculating the cost of the battery storage system. It is the Company's belief that this cost is warranted for safety and protection of employees as well as the assets.

<sup>8</sup> Real 2020\$; prices drop by 34% in nominal terms assuming 2.5% inflation rate.

- Due to low installed capacity and limited operational experience with battery storage on the DEP system, the Company assumes that system integration costs of a battery would be on the level of a custom application rather than a basic, or turnkey, level of cost. It is likely however, that as battery storage becomes more pervasive on the DEP system, system integration costs will decline, and battery storage costs could decline further than the near 50% decline already assumed in the IRP. The Company will monitor developments in this area and adjust as appropriate in future IRPs.

As stated previously, it is very difficult to determine what is included in the cost assumptions for battery storage in publications, particularly with regards to software and controls, HVAC, fire detection and suppression, and system integration costs. The following are the assumptions the Company includes for the percent contribution of costs from various components of a battery storage system along with the projected cost trend through 2029 in nominal terms assuming 2.5% inflation.<sup>9</sup>

**TABLE H-1**  
**COST COMPONENTS OF BATTERY STORAGE IN 2020 IRP**

COMPONENT	% OF TOTAL COST <sup>10</sup>	PROJECTED COST TREND THROUGH 2029
Battery Pack	53%	-51%
Power Electronics	3%	-40%
Software and Controls	1%	-8%
Balance of Plant	9%	-15%
Systems Integration	15%	-30%
Site Installation	8%	3%
Project Development Fees	6%	-24%
Interconnection Fees	5%	25%

As further context to the above cost allocations and assumptions, EPRI recently conducted a survey of its members regarding cost assumptions of battery storage. Many members use public sources such as NREL, Lazard, and EPRI, in addition to commercial third-party forecasts and in-house SME

<sup>9</sup> Initial value based on 2020 cost of a 50 MW / 200 MWh battery storage system in the 2020 IRP.

<sup>10</sup> Values based on total cost without owner's costs. Owner's costs are consistent with the costs incurred during the development of the Company's previous storage projects.



input, when developing battery storage price forecasts. Importantly, members do not simply rely on published numbers without making some adjustments. Members identified adding costs for items such as interconnection, A/C balance of plant, substation, land, and civic infrastructure. Nearly half of respondents factor in costs associated with a state of charge (SOC) window or depth of discharge limitation when developing cost estimates. Finally, one cost that DEP does not account for are end-of-life costs for disposal and recycling of battery storage components. Just over half of respondents account for these costs and the Company will evaluate adding end-of-life costs in future IRPs.

## EFFECTIVE LOAD CARRYING CAPABILITY (ELCC) OF BATTERY STORAGE

The Company commissioned Astrape Consulting, a nationally recognized expert in the field, to conduct a Storage Effective Load Carrying Capability (ELCC) Study of battery storage to determine the capacity value that short-duration storage can provide towards meeting DEP's winter peak demand. The ELCC study evaluated both standalone storage, as well as DC coupled solar plus storage over a range of storage penetrations, durations, and solar levels. The results of the study are highlighted below, and the full report is filed with the IRP as Attachment IV. Importantly, the study confirmed that initial additions of storage can provide nearly 100% contribution to winter peak, however the ELCC contribution of energy storage decreases rapidly with increasing penetration of battery storage as is the case with any energy limited resource.

## STANDALONE STORAGE ELCC

The following matrix depicts the range of scenarios evaluated in the ELCC study under a base level of solar (4,000 MW) and a high level of solar (5,500 MW).

TABLE H-2

## STANDALONE STORAGE RUN MATRIX FOR ELCC STUDY

Duration Cumulative Battery Capacity	STANDALONE BATTERY DURATION (HRS)		
	2	4	6
800 MW			
1,600 MW (incr 800)			
2,400 MW (incr 800)			
3,200 MW (incr 800)			

The sensitivities analyzed in the matrix above were conducted separately for each battery duration. For example, 6-hour batteries were studied as if there were no 4-hour or 2-hour batteries on the DEP system. In this manner, the ELCC represents the value of a 6-hour battery without the impacts of other incremental storage on the system. An additional sensitivity was analyzed which studied the impacts of 6-hour storage if up to 1,600 MWs of 6-hour storage were placed on the system *after* 3,200 MWs of 4-hour storage were already operating in DEP.

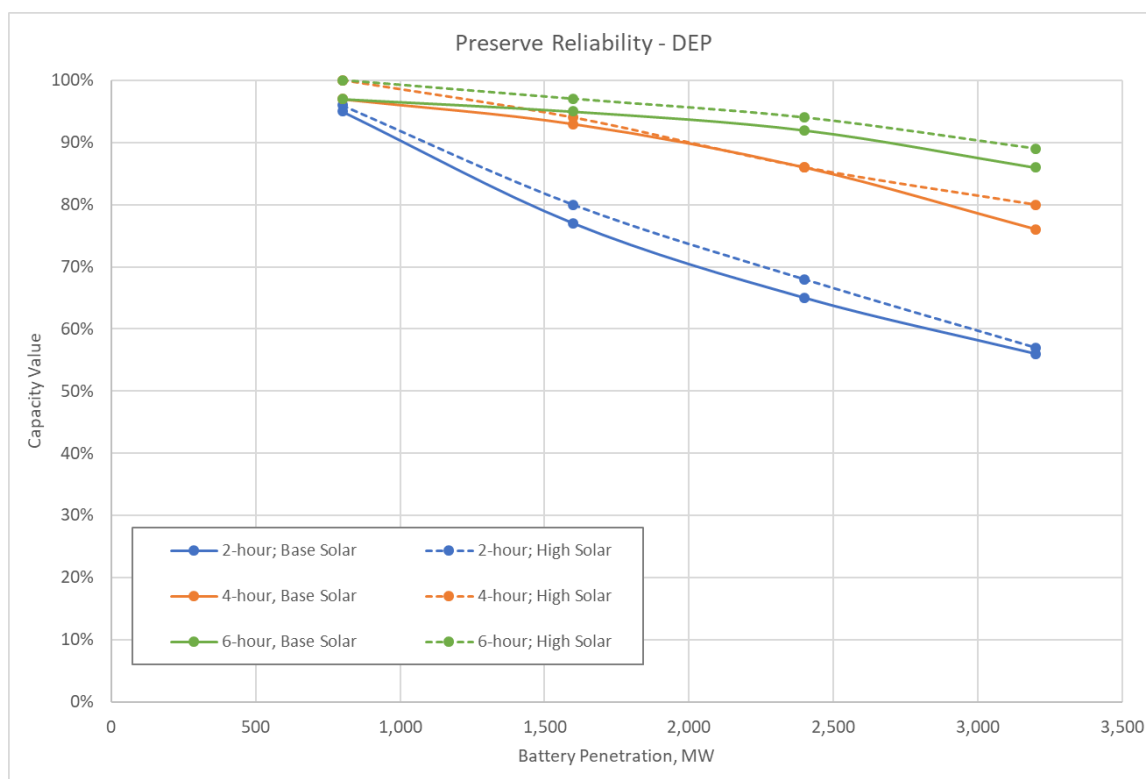
The ELCC of standalone storage was determined separately under the following three conditions:

- Preserve Reliability – Assumes full control of the battery and only dispatches the battery during emergency events to avoid firm load shed, maintains charge at all times possible. Results in highest possible capacity value but low economic value.
- Economic Arbitrage – Assumes DEP maintains full control of the battery and dispatches the battery based on a daily schedule to maximize economics. This mode of operation allows for the schedule to deviate during emergency events as they occur. Uncertainty in the model is driven by generator outages, day ahead load and solar uncertainty.
- Fixed Dispatch – Assumes DEP has no control of the battery, and the battery charges and discharges against a fixed set of prices. To model this condition, hourly avoided cost values

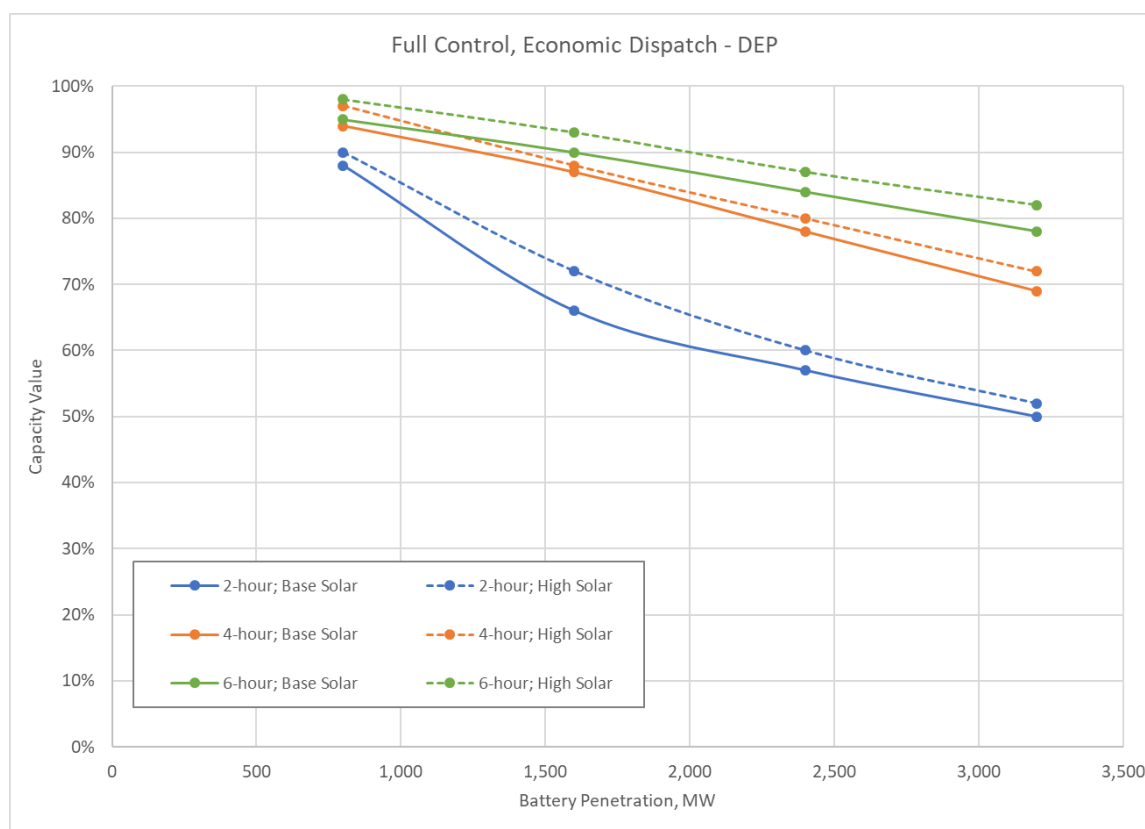
from NC Docket E-100 Sub 158 were used to set the dispatch schedule of the battery. This scenario was developed to demonstrate the impact to storage capacity value if DEP did not have dispatch rights to the storage asset.

The following three charts depict the capacity value of 2-hour, 4-hour, and 6-hour storage under the three operating conditions described above.

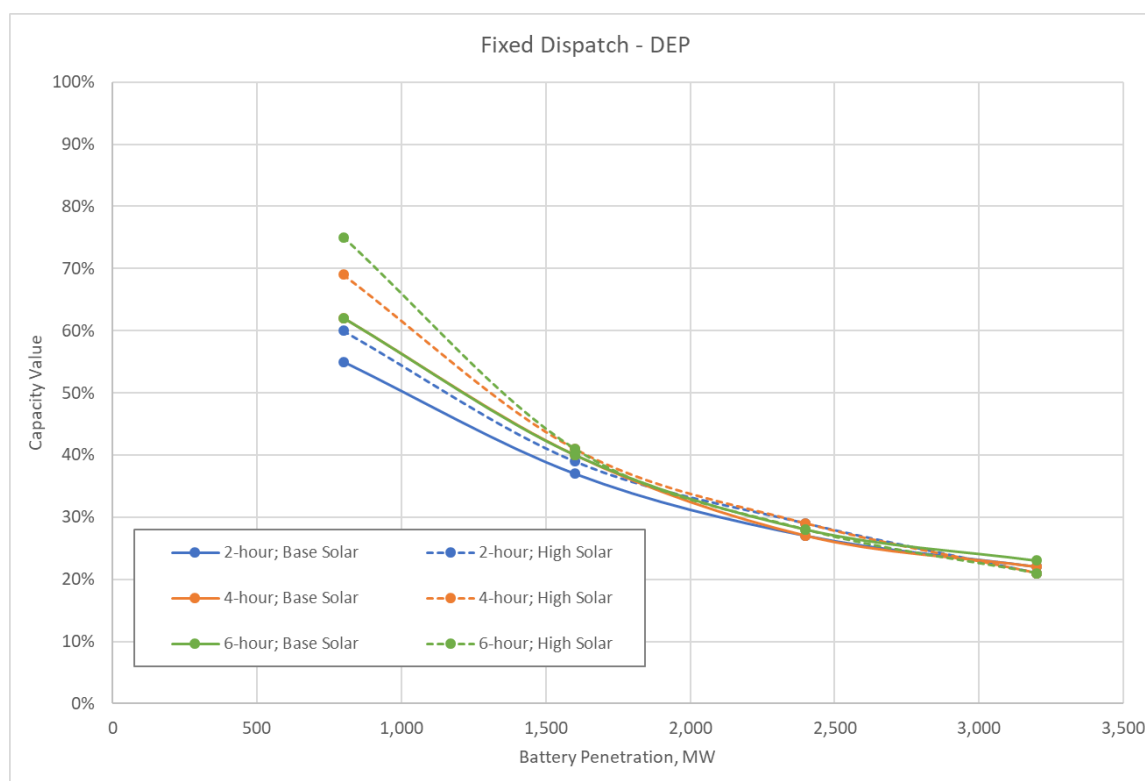
**FIGURE H-3**  
**AVERAGE CONTRIBUTION TO DEP WINTER PEAK IN PRESERVE RELIABILITY MODE**



**FIGURE H-4**  
**AVERAGE CONTRIBUTION TO DEP WINTER PEAK IN ECONOMIC**  
**DISPATCH MODE**



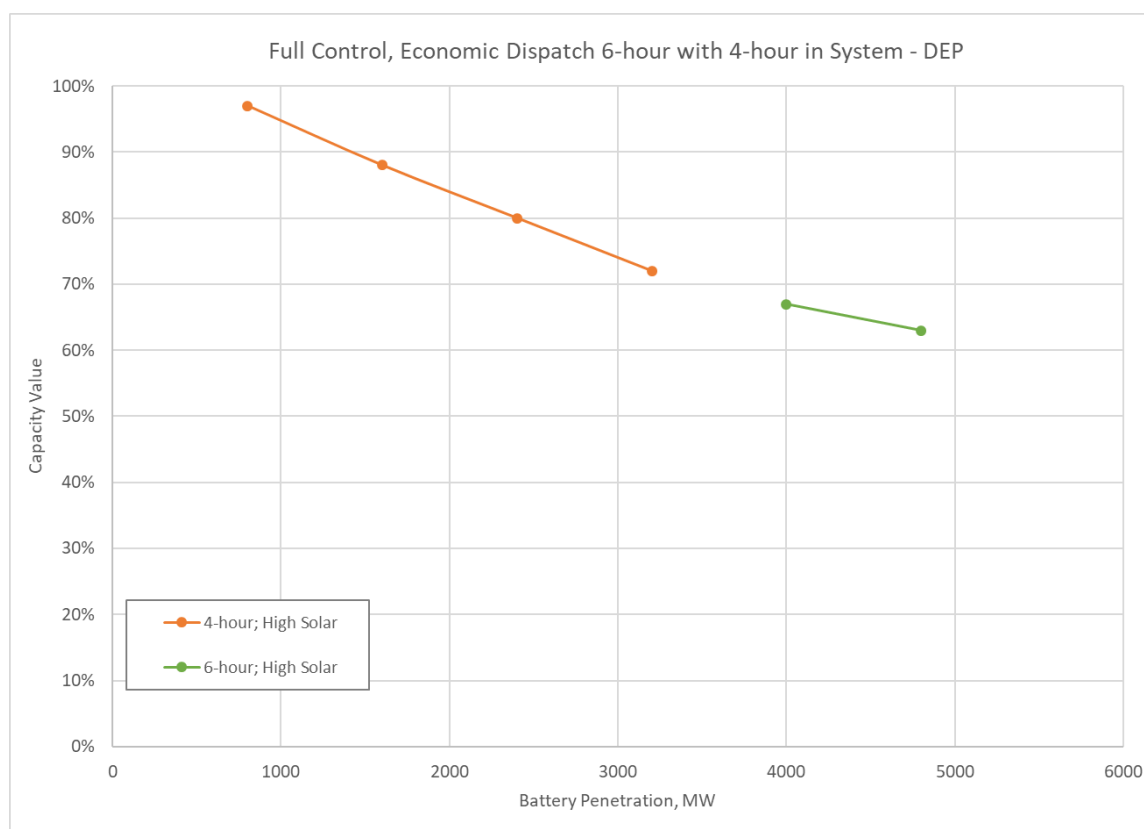
**FIGURE H-5**  
**AVERAGE CONTRIBUTION TO DEP WINTER PEAK IN FIXED DISPATCH**  
**MODE**



The results of the sensitivity of 6-hour storage added after 3,200 MW of 4-hour storage are shown in the following chart.

FIGURE H-6

## AVERAGE CONTRIBUTION TO DEP WINTER PEAK FOR 6-HOUR STORAGE WITH 4-HOUR ON SYSTEM



Based on the results of the study, DEP made the following assumptions in development of the 2020 IRP:

- **All storage capacity values based on Economic Dispatch** – The IRP model maximizes the value of battery storage by charging the battery with lower cost energy and discharging the stored energy during periods where energy has more value. The model does not maintain full charge in all hours and forego economic benefit to customers to ensure the battery is available to meet demand if a generator on the system experiences an unplanned outage. Similarly, in practice, a board operator does not have perfect foresight of forced outages and would likely use the battery when it is economically prudent based on what they see at the time. Alternatively, as demonstrated in the results above, the value of battery storage for DEP's

customers is maximized when the utility maintains dispatch rights for the battery asset. For these reasons, the Company relied on the ELCC results modeled under Economic Arbitrage conditions.

- **Only 4-hour and 6-hour storage considered for standalone storage** – Under all dispatch options, the value of 2-hour storage quickly diminishes as their penetration increases on the system. As shown in Appendix B of the Resource Adequacy report (Attachment III to the IRP), even though most of the LOLH occurs in the hour beginning 7AM, DEP has LOLH over a range of hours in the morning and evening which limits the value that 2-hour storage can provide to the system. Additionally, two-hour storage generally performs the same function as DSM programs that, not only reduce winter peak demand, but also tend to flatten demand by shifting energy from the peak hour to hours just beyond the peak. This flattening of peak demand is one of the main drivers for rapid degradation in capacity value of 2-hours storage. As the Company seeks to expand winter DSM programs, the value of two-hour storage will likely diminish.

While the above results show the average capacity value attributed to varying levels of storage on the DEP system, the incremental value of adding 800 MW blocks of storage can be calculated from the results. The incremental values are useful when determining the capacity value of the next block of energy storage, particularly when evaluating replacing a CT with a 4-hour battery as discussed in Appendix A and the economic coal retirement discussion Chapter 11. The incremental capacity value of storage assumed in the IRP is shown in the following table.



TABLE H-3

INCREMENTAL CONTRIBUTION TO PEAK FOR 4- AND 6-HOUR  
STORAGE IN DEP

SOLAR PENETRATION	DURATION	STORAGE CAPACITY	INCREMENTAL CONTRIBUTION TO WINTER PEAK
Base Renew	4-hour	0 - 800	95%
		800 - 1,600	80%
		1,600 - 2,000	70%
	6-hour	0 - 800	95%
		800 - 1,600	85%
		1,600 - 2,600	70%
High Renew	4-hour	0 - 800	100%
		800 - 1,600	80%
		1,600 - 2,100	70%
	6-hour	0 - 800	100%
		800 - 1,600	90%
		1,600 - 2,400	75%

For planning purposes, the Company installed a lower limit of 70% incremental contribution to winter peak before moving to 6-hour storage. In that case, DEP assumed the following incremental contribution to winter peak for 4- and 6-hour storage.

TABLE H-4

## INCREMENTAL CONTRIBUTION TO PEAK FOR 6-HOUR STORAGE WITH 4-HOUR ON SYSTEM

SOLAR PENETRATION	DURATION	STORAGE CAPACITY	INCREMENTAL CONTRIBUTION TO WINTER PEAK
High Renew	4-hour	0 - 800	100%
		800 - 1,600	80%
		1,600 - 2,100	70%
	6-hour	2,100 - 3,000	65%
		3,000 - 3,800	55%
		3,800 - 4,800	45%

## SOLAR PLUS STORAGE ELCC

The following matrix depicts the range of scenarios evaluated in the ELCC study assuming a 2-hour or 4-hour battery were coupled with solar.

TABLE H-5

## SOLAR PLUS STORAGE RUN MATRIX FOR ELCC STUDY

PROJECT MAX CAPACITY (MW)	SOLAR CAPACITY (MW)	TOTAL BATTERY (MW/% OF SOLAR)	REGION EXISTING SOLAR BEFORE ADDING COMBINED PLUS STORAGE PROJECT (MW)
800	800	80 (10%)	3,200
800	800	240 (30%)	3,200
800	800	400 (50%)	3,200
1,600	1,600	160 (10%)	3,900
1,600	1,600	480 (30%)	3,900
1,600	1,600	800 (50%)	3,900

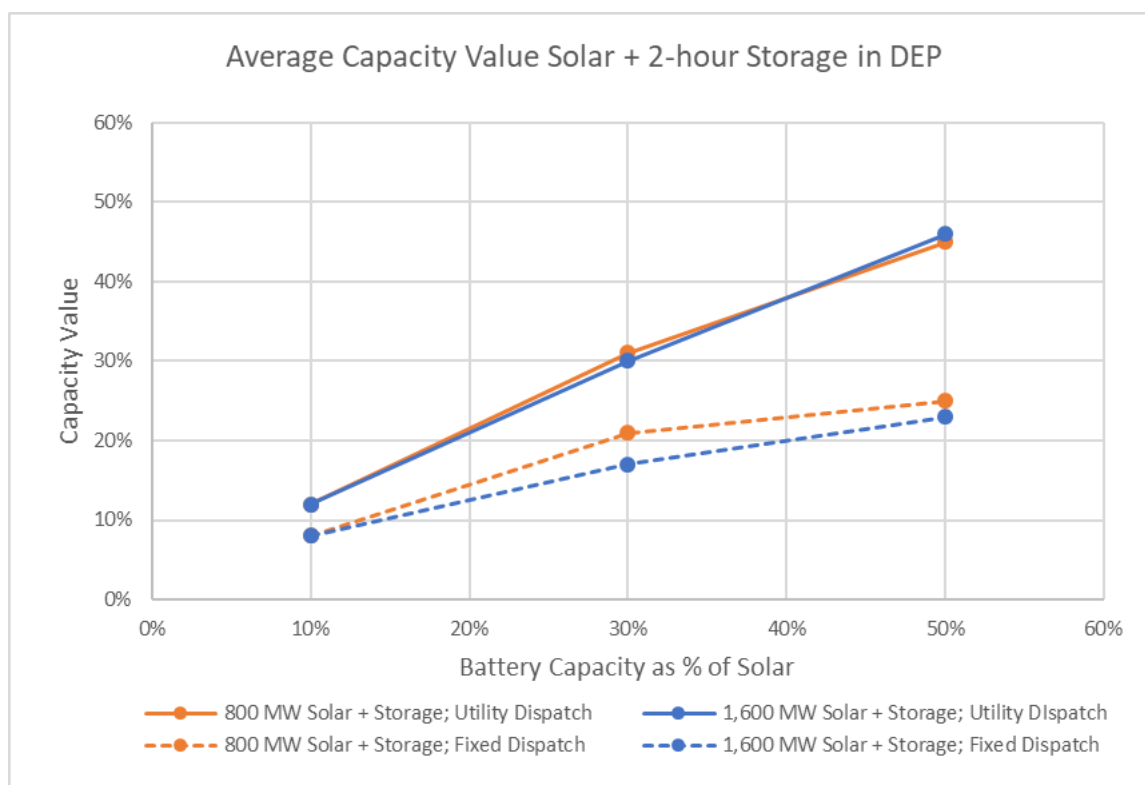
Solar plus storage capacity value was analyzed with 2- and 4-hour battery storage representing 10%, 30%, and 50% of the nameplate solar MW. This evaluation was conducted with 800 and 1,600 MW of solar paired with storage out of 4,000 MW to 5,500 MW of total solar on the DEP system. The ELCC of standalone storage was determined separately under the following two conditions:

- **Economic Arbitrage** – Assumes DEP maintains full control of the battery and dispatches the battery based on a daily schedule to maximize economics. This mode of operation allows for the schedule to deviate during emergency events as they occur. Uncertainty in the model is driven by generator outages, day ahead load and solar uncertainty.
- **Fixed Dispatch** – Assumes DEP has no control of the battery, and the battery charges and discharges against a fixed set of prices. To model this condition, hourly avoided cost values from NC Docket E-100 Sub 158 were used to set the dispatch schedule of the battery. This scenario was developed to demonstrate the impact to storage capacity value if DEP did not have dispatch rights to the storage asset.

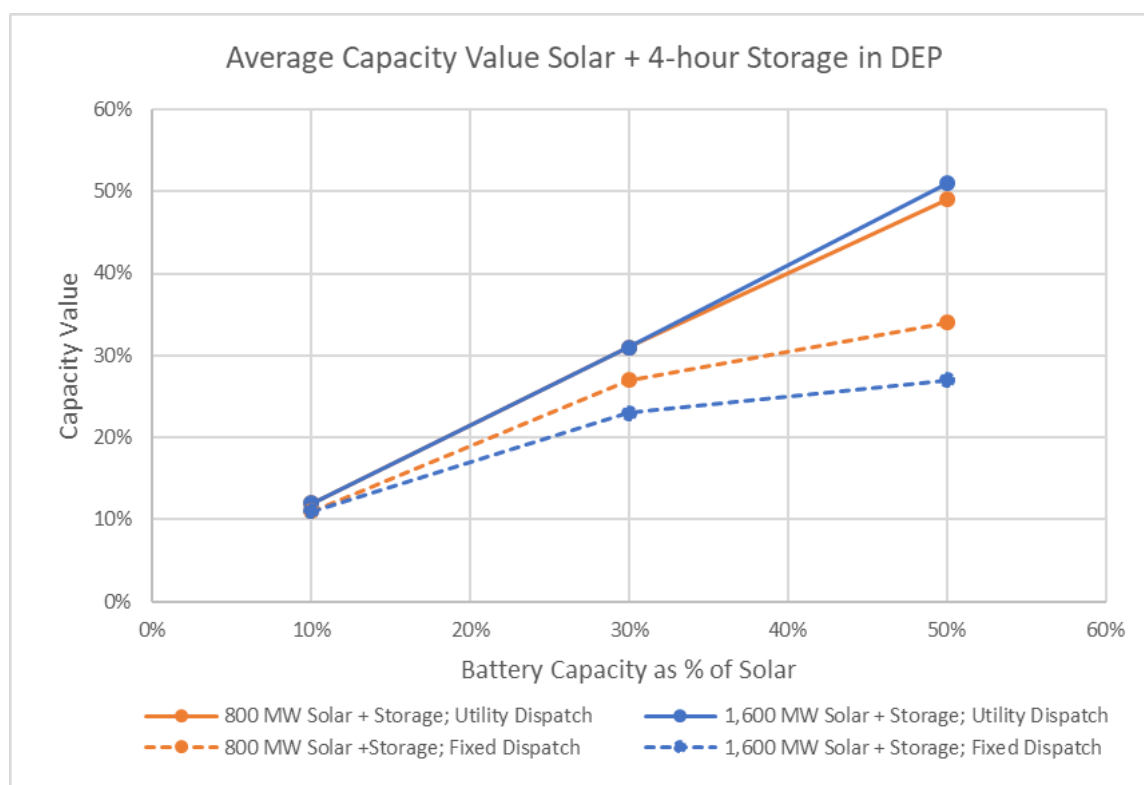
The following chart depicts the contribution to winter peak of solar plus storage under the two dispatch modes. The contribution to peak is the contribution of the solar MWs (i.e. a 100 MW solar facility

with 25 MW of storage that provides 25% contribution to peak provides 25 MW towards meeting winter peak demand).

**FIGURE H-7**  
**AVERAGE CONTRIBUTION TO DEP WINTER PEAK OF SOLAR PLUS 2-HOUR DURATION STORAGE**



**FIGURE H-8**  
**AVERAGE CONTRIBUTION TO DEP WINTER PEAK OF SOLAR PLUS 4-HOUR DURATION STORAGE**



Based on the results of the study, and for the same reasons as discussed in the standalone section above, DEP made the following assumptions in development of the 2020 IRP for solar plus storage:

- All solar plus storage capacity values based on Economic Dispatch. The Company will monitor how solar plus storage assets materialize on the system and will adjust this assumption in future IRPs if necessary.
- Only 4-hour considered for storage paired with solar

Additionally, for solar paired with storage in DEP, the Company assumed that the capacity of storage was 25% of the nameplate capacity of the solar the storage was paired with. Based on the results of the ELCC study, the Company assumed that this solar plus storage provided 25% of the solar

nameplate capacity towards meeting winter peak demand. Also, the solar plus storage projects were capped at the solar capacity, so a 400 MW solar facility paired with 100 MW of battery storage provided a maximum output of 400 MW and was ascribed 100 MW of capacity value.

## CONSIDERATIONS FOR FUTURE STUDIES

For some of the portfolios presented in the IRP, specifically the No New Gas Portfolio (Pathway F), and to a lesser extent, the 70% carbon reduction portfolios (Pathways D and E), the level of solar plus storage exceeded the penetration of storage evaluated in the ELCC study. Additionally, in the no new gas portfolios, significant levels of standalone storage would likely deteriorate the capacity value of solar plus storage resources. The combination of standalone storage and solar plus storage was also not evaluated in the ELCC. In all cases, the contribution to winter peak for solar plus storage was assumed to equal the percentage of storage paired with solar. For these reasons, the contribution to winter peak demand of solar plus storage later in the planning horizon is likely overstated. Future storage ELCC studies should evaluate:

- Higher penetrations of solar plus storage
- The impacts of standalone storage on the value of solar plus storage





# ENVIRONMENTAL COMPLIANCE



## APPENDIX I: ENVIRONMENTAL COMPLIANCE

Duke Energy Progress, which is subject to the jurisdiction of Federal agencies including the Federal Energy Regulatory Commission, EPA, and the NRC, as well as State commissions and agencies, is potentially impacted by State and Federal legislative and regulatory actions. This section provides a high-level description of several issues Duke Energy Progress is actively monitoring or engaged in that could potentially influence the Company's existing generation portfolio and choices for new generation resources.

### AIR QUALITY



Duke Energy Progress is required to comply with numerous State and Federal air emission regulations, including the federal Acid Rain Program (ARP), the Cross-State Air Pollution Rule (CSAPR) NO<sub>x</sub> and SO<sub>2</sub> cap-and-trade program, the Mercury and Air Toxics Standards (MATS) rule, and the 2002 North Carolina Clean Smokestacks Act (NC CSA).

As a result of complying with these regulations, Duke Energy Progress reduced SO<sub>2</sub> emissions by approximately 97% from 2000 to 2019 and reduced NO<sub>x</sub> emissions by approximately 92% from 1996 to 2019. While the NC CSA was instrumental in achieving significant emission reductions to benefit air quality in North Carolina, recent federal regulations now impose more stringent requirements, as noted below.

The following is a summary of the major air related federal regulatory programs that are currently impacting, or that could impact, Duke Energy Progress operations in North Carolina.

### CROSS-STATE AIR POLLUTION RULE (CSAPR)

The "good neighbor" provision of the Clean Air Act requires states in their State Implementation Plans (SIPs) to address interstate transport of air pollution that affects downwind states' ability to attain and maintain National Ambient Air Quality Standards (NAAQS). If states do not submit SIPs or EPA does not approve them, EPA must issue Federal Implementation Plans (FIPs) as a backstop. EPA has created several regulatory programs via the FIP process to address these emissions, including the Clean Air Interstate Rule (CAIR), the Cross-State Air Pollution Rule (CSAPR), and most recently, the CSAPR Update Rule. These programs establish state emission budgets for SO<sub>2</sub> and NO<sub>x</sub> on an annual basis, and NO<sub>x</sub> during ozone season (May 1-September 30.)

On September 7, 2016, EPA finalized the CSAPR Update Rule which reduces the ozone season NO<sub>x</sub> emission budgets from those promulgated in the original CSAPR Rule. The rule also removed North Carolina from CSAPR's ozone season NO<sub>x</sub> program beginning in 2017. However, Duke Energy units in North Carolina remain subject to annual NO<sub>x</sub> and SO<sub>2</sub> emission limits.

The Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) recently decided environmental and industry challenges to the 2016 CSAPR Update Rule. The Court remanded the rule back to EPA for revision, and DEP expects EPA to issue a proposal addressing the Court's ruling by October 2020. However, EPA's determination that North Carolina sources should be excluded from the CSAPR Update Rule because they do not significantly contribute to downwind ozone non-attainment was not challenged and was not included in the remand from the D.C. Circuit Court.

## MERCURY AND AIR TOXICS STANDARDS (MATS) RULE

On February 16, 2012, EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which established emission limits for hazardous air pollutants (HAP) from new and existing coal-fired and oil-fired steam electric generating units. The rule required sources to comply with emission limits by April 16, 2015, or by April 16, 2016 with an approved extension. Duke Energy Progress is complying with all rule requirements.

In June 2015, the Supreme Court determined that EPA had unreasonably refused to consider costs when it determined that it was appropriate and necessary to regulate hazardous air pollutants from coal-fired and oil-fired steam electric generating units and remanded the case to the D.C. Circuit Court for further proceedings.

On May 22, 2020, EPA published a final rule and concluded that it is not "appropriate and necessary" to regulate power plant HAP emissions. However, EPA declined to rescind the 2012 MATS rule. In addition, EPA issued the results of its statutorily required Residual Risk and Technology Review (RTR) and determined that no changes to the MATS emission standards are needed.

## NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS)

### 8-HOUR OZONE NAAQS

In October 2015, EPA finalized revisions to the primary (health-based) and secondary (welfare-based) 8-Hour ozone national ambient air quality standard (NAAQS), lowering them from 75 to 70 parts per billion (ppb.) EPA finalized area designations for the 2015 ozone standard and did not designate any nonattainment areas in North Carolina.

In August 2019, the D.C. Circuit decided challenges from state, environmental, and industry challengers to the 2015 standard. The Court upheld the primary standard but remanded the secondary standard to EPA for “further explanation and reconsideration.”

### SO<sub>2</sub> NAAQS

On June 22, 2010, EPA finalized revisions to the sulfur dioxide (SO<sub>2</sub>) NAAQS, establishing a 1-hour standard of 75 ppb.

To demonstrate attainment of the NAAQS, the North Carolina Department of Environmental Quality was required to assess the air quality near large industrial sources of SO<sub>2</sub> emissions, including coal-fired power plants. Based on air quality modeling, NC DEQ provided a demonstration to EPA that the area surrounding the Mayo Station was in attainment. NC DEQ required Duke Energy Progress to conduct ambient air quality monitoring near the Asheville and Roxboro Stations for the period 2017 to 2019 to determine whether those areas were in attainment. Data collected during the period supports an attainment determination, and NC DEQ has submitted its recommendation for classification as attainment to EPA along with a request to discontinue the monitoring at those sites. EPA has a legal obligation to issue a final determination of the attainment classification by December 31, 2020.

On March 8, 2019, after the periodic review required under the Clean Air Act, EPA issued a final rule retaining the SO<sub>2</sub> NAAQS standards, without revision.

## FINE PARTICULATE MATTER (PM<sub>2.5</sub>) NAAQS

On December 14, 2012, the EPA finalized revisions to the PM<sub>2.5</sub> (fine particle) NAAQS, establishing an annual average standard of 12 micrograms per cubic meter and a 24-hour standard of 35 micrograms per cubic meter. The EPA finalized area designations for this standard in December 2014. That designation process did not result in any areas in North Carolina being designated nonattainment. On April 30, 2020, EPA proposed to retain the standards, without revision.

## GREENHOUSE GAS REGULATION

On October 23, 2015, the EPA published a final rule establishing carbon dioxide (CO<sub>2</sub>) emissions limits for new, modified and reconstructed power plants. The requirements for new plants apply to plants that commenced construction after January 8, 2014. EPA set an emission standard for new coal units of 1,400 pounds of CO<sub>2</sub> per gross MWh, which would require the application of partial carbon capture and storage (CCS) technology for a coal unit to be able to meet the limit. The EPA set a final standard of 1,000 pounds of CO<sub>2</sub> per gross MWh for new natural gas combined cycle (NGCC) units. Duke Energy Progress considers the standard for NGCC units to be achievable.

On December 20, 2018, EPA proposed revised NSPS standards. The proposed emission limit for new and reconstructed coal units is 1,900 pounds of CO<sub>2</sub>/MWh, which is intended to reflect what has been demonstrated by the most efficient coal units without the use of CCS. The requirements apply to plants that commenced construction after December 20, 2018. EPA did not propose to change the standard established in 2015 for new or reconstructed natural gas combined-cycle units.

On October 23, 2015, the EPA published the Clean Power Plan (CPP) final rule, regulating CO<sub>2</sub> emissions from existing coal and natural gas units. The CPP established CO<sub>2</sub> emission rates and mass cap goals that apply to existing fossil fuel-fired Electric Generating Units (EGUs). Petitions challenging the rule were filed by numerous groups, and on February 9, 2016, the Supreme Court issued a stay of the final CPP rule, halting its implementation.

On July 8, 2019, EPA finalized the Affordable Clean Energy (ACE) rule, and in a separate but related rule repealed the Clean Power Plan and established CO<sub>2</sub> emission standards for existing coal-fired power plants only. EPA declined to set standards for existing natural gas plants. States have until July 8, 2022, to submit plans based on application of efficiency improvements at existing coal-fired power plants to EPA for approval. Various environmental groups, states, and industry groups have filed

petitions for review in the D.C. Circuit challenging the ACE rule, whereas many states and industry groups have intervened on behalf of EPA to defend the rule.

## WATER QUALITY AND BY-PRODUCTS ISSUES

### CWA 316(B) COOLING WATER INTAKE STRUCTURES



Federal regulations implementing §316(b) of the Clean Water Act (CWA) for existing facilities were published in the Federal Register on August 15, 2014, with an effective date of October 14, 2014. The rule regulates cooling water intake structures at existing facilities to address environmental impacts from fish being impinged (pinned against cooling water intake structures) and entrained (being drawn into cooling water systems and affected by heat, chemicals or physical stress). The final rule establishes aquatic protection requirements at existing facilities and new on-site generation that withdraw 2 million gallons per day (MGD) or more from rivers, streams, lakes, reservoirs, estuaries, oceans, or other waters of the United States. All DEP nuclear fueled, coal-fired and combined cycle stations in South Carolina and North Carolina are affected sources.

The rule establishes two standards, one for impingement and one for entrainment. To demonstrate compliance with the impingement standard, facilities must choose and implement one of the following options:

- Closed cycle re-circulating cooling system; or
- Demonstrate the maximum design through screen velocity is less than 0.5 feet per second (fps) under all conditions; or
- Demonstrate the actual through screen velocity, based on measurement, is less than 0.5 fps; or
- Install modified traveling water screens and optimize performance through a two-year study; or
- Demonstrate a system of technologies, practices, and operational measures are optimized to reduce impingement mortality; or
- Demonstrate the impingement latent mortality is reduced to no more than 24% annually based on monthly monitoring.

In addition to these options, the final rule allows the state permitting agency to establish less stringent standards if the capacity utilization rate is less than 8% averaged over a continuous 24-month period. The rule, also, allows the state permitting agency to determine no further action warranted if impingement is considered *de minimis*. Compliance with the impingement standard is not required until requirements for entrainment are established.

The entrainment standard does not mandate the installation of a technology but rather establishes a process for the state permitting agency to determine necessary controls, if any, required to reduce entrainment mortality on a site-specific basis. Facilities that withdraw greater than 125 MGD are required to submit information to characterize entrainment and assess the engineering feasibility, costs, and benefits of closed-cycle cooling, fine mesh screens and other technological and operational controls. The state permitting agency can determine no further action is required, or require the installation of fine mesh screens, or conversion to closed-cycle cooling.

The rule requires facilities to submit all necessary 316(b) reports in accordance with its Clean Water Act (CWA) discharge permit and schedule developed by the state permitting agency. The Company expects the state permitting authority to determine necessary controls for the affected DEP facilities in the 2022 to 2024 timeframe and intake modifications, if necessary, to be required in the 2023 to 2026 timeframe.

## STEAM ELECTRIC EFFLUENT GUIDELINES

Federal regulations revising the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (“ELG Rule”) were published in the Federal Register on November 3, 2015, with an effective date of January 4, 2016. While the ELG Rule is applicable to all steam electric generating units, waste streams affected by these revisions are generated at DEP’s existing coal-fired facilities. The revisions prohibit the discharge of bottom and fly ash transport water, and flue gas mercury control wastewater, and establish technology-based limits on the discharge of wastewater generated by Flue Gas Desulfurization (FGD) systems, and leachate from coal combustion residual (CCR) landfills and impoundments. The rule also establishes technology-based limits on gasification wastewater, but this waste stream is not generated at any of the DEP facilities. Affected facilities must comply between 2018 and 2023, depending on timing of its Clean Water Act (CWA) discharge permit.<sup>1</sup>

<sup>1</sup> On September 12, 2017, EPA finalized a rule (“the Postponement Rule”) to postpone the earliest compliance date for bottom ash transport water and FGD wastewater for a period of two years (i.e. November 1, 2020), but this rule did not extend the latest compliance date of Dec. 31, 2023 and did not revise the earliest compliance date for fly ash transport water. The Postponement Rule was subsequently upheld by the Fifth Circuit Court of Appeals on August 28, 2019.

Petitions challenging the rule were filed by several groups and all challenges to the rule were consolidated in the Fifth Circuit Court of Appeals. On August 11, 2017, the EPA Administrator signed a letter announcing his decision to conduct a rulemaking to consider revising the new, more stringent effluent limitations and pretreatment standards for existing sources in the final rule that apply only to bottom ash transport water and FGD wastewater. On August 22, 2017, the Fifth Circuit Court of Appeals granted EPA's Motion to Govern Further Proceedings, thereby severing and suspending the claims related to flue gas desulfurization wastewater, bottom ash transport water and gasification wastewater. Subsequently, challenges to the limits for fly ash transport water and gasification wastewater were voluntarily dismissed while litigation on the limits for legacy wastewater and CCR leachate continued.

On April 12, 2019, the Fifth Circuit vacated and remanded portions of the rule dealing with legacy wastewater and CCR leachate. It is unknown when EPA will propose new limits for these waste streams.

The proposed rule revising the more stringent effluent limitations and pretreatment standards for bottom ash transport water and FGD wastewater was published on November 22, 2019. The public comment period ended on January 21, 2020. The rule is anticipated to be finalized in 3<sup>rd</sup> quarter 2020.

All DEP coal-fired units have technologies installed to meet the requirements in the 2015 ELG Rule. The anticipated final rule revising the more stringent effluent limitations and pretreatment standards for bottom ash transport water and FGD wastewater is not expected to require the installation of any additional technology.

## COAL COMBUSTION RESIDUALS



In January 2009, following Tennessee Valley Authority's Kingston ash pond dike failure, Congress issued a mandate to EPA to develop federal regulations for the disposal of coal combustion residuals (CCR). CCR includes fly ash, bottom ash, boiler slag, and flue gas desulfurization solids. On April 17, 2015, EPA finalized the first federal regulations for the disposal of CCR. The 2015 CCR rule regulates CCR as a nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA) and allows for beneficial use of CCR with some restrictions.

The 2015 CCR rule applies to all new and existing landfills, new and existing surface impoundments that were still receiving CCR as of the effective date of the rule, and existing surface impoundments that were no longer receiving CCR but contained liquids as of the effective date of the rule, provided these



units were located at stations generating electricity (regardless of fuel source) as of the effective date of the rule. The rule establishes national minimum criteria that include location restrictions, design standards, structural integrity criteria, groundwater monitoring and corrective action, closure and post-closure care requirements, and recordkeeping, reporting, and other operational procedures to ensure the safe management and disposal of CCR.

The 2015 CCR rule was challenged in litigation by industry and environmental petitioners. In August 2018, the D.C. Circuit Court vacated provisions that allowed unlined and clay-lined impoundments to continue to operate, finding those provisions violated the RCRA protectiveness standard. In response to the D.C. Circuit decision, EPA proposed two rulemakings to address unlined impoundments. The “Part A” rule, which was proposed on December 2, 2019, would establish an August 31, 2020 deadline to cease placement of CCR and non-CCR wastestreams into unlined ash basins and initiate closure (although that date is expected to be moved back in the final rule.)

The “Part B” rule, which was proposed on March 3, 2020, would establish a process for owners/operators to make an alternate liner demonstration. The proposal also included other significant provisions, including EPA’s reiteration of its view that the use of CCR in units subject to forced closure is prohibited under the current CCR regulations. However, EPA proposed two options for allowing the use of CCR in surface impoundments and landfills for the purpose of supporting closure. In addition, EPA proposed a new closure-by-removal option, which would allow owners/operators to complete groundwater corrective action during the post-closure care period.

In February 2020, EPA published a proposed rule to establish a federal permitting program for CCR surface impoundments and landfills in states that do not have approved state permit programs, as provided under the 2016 WIIN Act. Only Oklahoma and Georgia currently have approved state programs, so this rule would apply in North Carolina until such a time that a state CCR permit program is approved by EPA.

In August 2019, EPA proposed amendments addressing CCR storage and criteria for unencapsulated beneficial uses that would require CCR storage piles to be completely enclosed (four walls and a roof), or would require control of releases and demonstration that the accumulation is “temporary” and that all CCR will be removed at some point in the future. EPA also proposed replacing the mass-based threshold for unencapsulated non-roadway beneficial uses to location-based criteria based on landfill location restrictions.

In addition to the requirements of the federal CCR regulation, CCR landfills and surface impoundments will continue to be independently regulated by North Carolina. On September 20, 2014, the North Carolina Coal Ash Management Act of 2014 (CAMA) became law and was amended on July 14, 2016.

CAMA establishes requirements regarding the beneficial use of CCR, the closure of existing CCR surface impoundments, the disposal of CCR at active coal plants, and the handling of surface and groundwater impacts from CCR surface impoundments. CAMA required eight “high-priority” CCR surface impoundments in North Carolina to be closed no later than December 31, 2019 (although that date was subsequently extended to August 1, 2022, for the two Asheville Station impoundments.) CAMA also required state regulators to provide risk-ranking classifications to determine the method and timing for closure of the remaining CCR surface impoundments. The North Carolina Department of Environmental Quality (NCDEQ) categorized all remaining CCR surface impoundments as low-risk after Duke Energy completed required dam safety repairs and established alternate permanent replacement water supplies for landowners with drinking water supply wells within a one-half-mile radius of CCR surface impoundments. Despite Duke Energy having taken these measures, on April 1, 2019, NCDEQ ordered that all remaining CCR surface impoundments in the state be closed by removal of CCR.

The impact from both state and federal CCR regulations to Duke Energy Progress is significant.





## NON-UTILITY GENERATION AND WHOLESALE



Corrected 11.06.2020

## APPENDIX J: NON-UTILITY GENERATION AND WHOLESALE

This appendix contains wholesale sales contracts, firm wholesale purchased power contracts and non-utility generation contracts.



TABLE J-1  
WHOLESALE SALES CONTRACTS

DEP AGGREGATED WHOLESALE SALES CONTRACTS									
COMMITMENT (MW)									
2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
3,386	4,113	4,130	4,151	4,203	4,085	4,129	4,170	4,213	4,237

NOTES:

- For wholesale contracts, Duke Energy Carolinas/Duke Energy Progress assumes all wholesale contracts will renew unless there is an indication that the contract will not be renewed.
- For the period that the wholesale load is undesignated, contract volumes are projected using the same methodology as was assumed in the original contract (e.g. econometric modeling, past volumes with weather normalization and growth rates, etc.).

TABLE J-2  
FIRM WHOLESale PURCHASED POWER CONTRACTS

PURCHASED POWER CONTRACT	WINTER CAPACITY (MW)	LOCATION	VOLUME OF PURCHASES (MWH) JUL '19 – JUN '20
Peaking	850	SC	310,015
Peaking	800	NC	160,700
Intermediate	373	NC	N/A
Intermediate	415	NC	113,643

NOTES: Data represented above represents contractual agreements. These resources may be modeled differently in the IRP.

## NON-UTILITY GENERATION FACILITIES – NORTH CAROLINA

Please refer to DEC and DEP Small Generator Interconnection Consolidated Annual Reports filed on March 12, 2020 in NCUC Docket No. E-100, Sub 113B for details on the DEP North Carolina NUGS. The DEP NUG facilities are comprised of 99% intermediate facilities while the remaining 1% represents baseload facilities. Currently, hydro is considered baseload, solar and other renewables are considered intermediate.

Please refer to Table J-3 DEP Non-Utility Generator Listing – North Carolina Facilities.



## NON-UTILITY GENERATION FACILITIES – SOUTH CAROLINA

Table J-4 contains non-utility generation contracts for facilities located in South Carolina.

Please refer to the attachment, Table J-4 DEP Non-Utility Generator Listing – South Carolina Facilities.



## DEP QF INTERCONNECTION QUEUE

Corrected 11.06.2020

## APPENDIX K: DEP QF INTERCONNECTION QUEUE

Qualified Facilities contribute to the current and future resource mix of the Company. QFs that are under contract are captured as designated resources in the base resource plan. QFs that are not yet under contract but in the interconnection queue may contribute to the undesignated additions identified in the resource plans. It is not possible to precisely estimate how much of the interconnection queue will come to fruition; however, the current queue clearly supports solar generation's central role in DEP's NC REPS compliance plan and HB 589.

Below is a summary of the interconnection queue as of July 31, 2020:

**TABLE K-1**  
**DEP QF INTERCONNECTION QUEUE**

UTILITY	FACILITY STATE	ENERGY SOURCE TYPE	NUMBER OF PENDING PROJECTS	PENDING CAPACITY (MW AC)
DEP	NC	Battery	5	153
		Solar	188	4,612
	NC Total		193	4,765
	SC	Solar	140	2,332
	SC Total		140	2,332
	DEP Total		333	7,097

NOTE: (1) Above table includes all QF projects that are in various phases of the interconnection queue and not yet generating energy.  
(2) Table does not include net metering interconnection requests.





L

TRANSMISSION PLANNED  
OR UNDER CONSTRUCTION

## APPENDIX L: TRANSMISSION PLANNED OR UNDER CONSTRUCTION

In this section, DEP provide details on transmission projects planned or under construction, as well as how DEP ensures transmission system adequacy.

### DEP IN-SERVICE TRANSMISSION

Table L-1 below reflects Duke Energy Progress installed transmission circuit miles at each voltage class.

**TABLE L-1**  
**DEP INSTALLED TRANSMISSION CIRCUIT MILES BY VOLTAGE CLASS**

CIRCUIT VOLTAGE	44 KV	66-69 KV	100 -199 KV	230 KV	345 KV	500+ KV
Duke Energy Progress		12	2,551	3,390		292

### DEP TRANSMISSION PLANNED OR UNDER CONSTRUCTION

This section lists the planned transmission line additions. A discussion of the adequacy of DEP's transmission system is also included. Table L-2 lists the transmission line projects planned to meet reliability needs. This section also provides other information pursuant to the North Carolina and South Carolina rules.

**TABLE L-2**  
**DEP TRANSMISSION LINE ADDITIONS**

YEAR	LOCATION		CAPACITY	VOLTAGE	COMMENTS
	FROM	TO	MVA	KV	
2020	Cleveland Matthews Rd. Tap	Cleveland Matthews Rd	621	230	New
2020	Jacksonville	Grants Creek	1195	230	New
2020	Newport	Harlowe	681	230	New
2023	Porters Neck Tap	Porters Neck	442	230	New
2024	Brunswick #1	Folkstone Tap Line	594	230	New
2024	Folkstone Tap Line	Jacksonville	594	230	New

### CEPCN / CPCN

Certificates of environmental compatibility and public convenience and necessity (CEPCN) for the construction of electric transmission lines in South Carolina and Certificates of Public Convenience and Necessity (CPCN) in North Carolina

(p) Plans for the construction of transmission lines in North Carolina and South Carolina (161 kV and above) shall be incorporated in filings made pursuant to applicable rules. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(1) *For existing lines, the information required on FERC Form 1, pages 422, 423, 424, and 425, except that the information reported on pages 422 and 423 may be reported every five years.*

Please refer to the Company's FERC Form No. 1 filed with FERC in April 2020.

(p) Plans for the construction of transmission lines in North Carolina and South

Carolina (161 kV and above) shall be incorporated in filings made pursuant to applicable rules. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(2) *For lines under construction, the following:*

- a. Commission docket number;*
- b. Location of end point(s);*
- c. Length;*
- d. Range of right-of-way width;*
- e. Range of tower heights;*
- f. Number of circuits;*
- g. Operating voltage;*
- h. Design capacity;*
- i. Date construction started;*
- j. Projected in-service date;*

## **CLEVELAND MATTHEWS ROAD 230 KV TAP LINE**

Project Description: Construct new 230 kV transmission line from the Erwin-Selma 230 kV Line in Johnston County to the Cleveland Matthews Road 230 kV Substation in Johnston County.

- a. NC Docket number: E-2, Sub 1150
- b. County location of end point(s); Johnston County
- c. Approximate length; 11.5 miles
- d. Typical right-of-way width for proposed type of line; 125 feet
- e. Typical tower height for proposed type of line; 80 – 120 feet
- f. Number of circuits; 1
- g. Operating voltage; 230 kV
- h. Design capacity; 621 MVA
- i. Date construction started; March 2019



- j. Projected in-service date; December 2020

## JACKSONVILLE – GRANTS CREEK 230 KV LINE

Project Description: Construct new 230 kV transmission line from the Jacksonville 230 kV Substation in Onslow County to the Grants Creek 230 kV Substation in Onslow County.

- a. NC Docket number: E-2, Sub 1102
- b. County location of end point(s); Onslow County
- c. Approximate length; 15 miles
- d. Typical right-of-way width for proposed type of line; 125 feet
- e. Typical tower height for proposed type of line; 80 – 120 feet
- f. Number of circuits; 1
- g. Operating voltage; 230 kV
- h. Design capacity; 1195 MVA
- i. Date construction started; September 2018
- j. In-service date; June 2020

## NEWPORT – HARLOWE 230 KV LINE

Project Description: Construct new 230 kV transmission line from the Newport 230 kV Substation in Carteret County to the Harlowe 230 kV Substation in Carteret County.

- a. NC Docket number: E-2, Sub 1113
- b. County location of end point(s); Carteret County
- c. Approximate length; 8 miles
- d. Typical right-of-way width for proposed type of line; 125 feet
- e. Typical tower height for proposed type of line; 80 – 120 feet
- f. Number of circuits; 1
- g. Operating voltage; 230 kV

- h. Design capacity; 681 MVA
- i. Date construction started; October 2018
- j. In-service date; June 2020

The following pages represent those projects in response to NC Rule R8-62 part (3).

### **PORTERS NECK 230 KV TAP LINE**

Project Description: Construct new 230 kV transmission line from the Castle Hayne-Folkstone 230 kV Line to the Porters Neck 230 kV Substation in New Hanover County.

- a. County location of end point(s); New Hanover County
- b. Approximate length; 4.5 miles
- c. Typical right-of-way width for proposed type of line; 125 feet
- d. Typical tower height for proposed type of line; 80 – 120 feet
- e. Number of circuits; 1
- f. Operating voltage; 230 kV
- g. Design capacity; 442 MVA
- h. Estimated date for starting construction; January 2022
- i. Estimated in-service date; June 2023

### **BRUNSWICK #1-FOLKSTONE 230 KV TAP LINE**

Project Description: Construct new 230 kV transmission line segment from the Brunswick- Jacksonville 230 kV Line (Brunswick #1 side) to the Folkstone 230 kV Substation in Onslow County.

- a. County location of end point(s); Onslow County
- b. Approximate length; 5 miles
- c. Typical right-of-way width for proposed type of line; 125 feet

- d. Typical tower height for proposed type of line; 80 – 120 feet
- e. Number of circuits; 1
- f. Operating voltage; 230 kV
- g. Design capacity; 594 MVA
- h. Estimated date for starting construction; January 2023
- i. Estimated in-service date; June 2024

## FOLKSTONE-JACKSONVILLE 230 KV TAP LINE

Project Description: Construct new 230 kV transmission line segment from the Brunswick- Jacksonville 230 kV Line (Jacksonville side) to the Folkstone 230 kV Substation in Onslow County.

- a. County location of end point(s); Onslow County
- b. Approximate length; 5 miles
- c. Typical right-of-way width for proposed type of line; 125 feet
- d. Typical tower height for proposed type of line; 80 – 120 feet
- e. Number of circuits; 1
- f. Operating voltage; 230 kV
- g. Design capacity; 594 MVA
- h. Estimated date for starting construction; January 2023
- i. Estimated in-service date; June 2024

## DEP TRANSMISSION SYSTEM ADEQUACY

DEP monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks 10 years ahead at projected generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The DEP transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability. DEP works with DEC, North Carolina Electric Membership Corporation (NCEMC)

and ElectriCities to develop an annual NC Transmission Planning Collaborative (NCTPC) plan for the DEP and DEC systems in both North and South Carolina. In addition, transmission planning coordinates with neighboring systems including Dominion Energy South Carolina Inc. (DESC; formerly SCE&G) and Santee Cooper under a number of mechanisms including legacy interchange agreements between DESC, Santee Cooper, DEP, and DEC.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with DEP's Transmission Planning Summary guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC Reliability Corporation (SERC) policy and North American Electric Reliability Corporation (NERC) Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades. The transmission system is planned to ensure that there are no equipment overloads and adequate voltage is maintained to provide reliable service. The most stressful scenario is typically at projected peak load with selected equipment out of service. A thorough screening process is used to analyze the impact of potential equipment failures or other disturbances. As problems are identified, solutions are developed and evaluated.

Transmission planning and requests for transmission service and generator interconnection are interrelated to the resource planning process. DEP currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Summary guidelines and the FERC Open Access Transmission Tariff (OATT). The Company performs studies to ensure transfer capability is acceptable to meet reliability needs and customers' expected use of the transmission system. Generator interconnection requests are studied in accordance with the Large and Small Generator Interconnection Procedures in the OATT and the North Carolina and South Carolina Interconnection Procedures. It should be noted that location, MW interconnection requested, resource/load characteristics, and prior queued requests, in aggregate can have wide ranging impacts on transmission network upgrades required to approve the interconnection request. In addition, the actual

costs for the associated network upgrades are dependent on escalating labor and materials costs. Based on recent realized cost from implementing transmission projects, the escalation of labor and materials costs in future years could be significant.

SERC audits DEP every three years for compliance with NERC Reliability Standards. Specifically, the audit requires DEP to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications. SERC conducted a NERC Reliability Standards compliance audit of DEP in 2019 and DEP received "No Findings" from the audit team.

DEP participates in several regional reliability groups to coordinate analysis of regional, sub- regional and inter-balancing authority area transfer capability and interconnection reliability. Each reliability group's reliability purposes are to:

- Assess the interconnected system's capability to handle large firm and non-firm transactions for purposes of economic access to resources and system reliability;
- Ensure that planned future transmission system improvements do not adversely affect neighboring systems; and
- Ensure interconnected system compliance with NERC Reliability Standards.

Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five- and ten-year future periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability.

Application of the practices and procedures described above ensures that DEP's transmission system continues to provide reliable service to its native load and firm transmission customers.





## ECONOMIC DEVELOPMENT



## APPENDIX M: ECONOMIC DEVELOPMENT

### CUSTOMERS SERVED UNDER ECONOMIC DEVELOPMENT:

In the NCUC Order issued in Docket No. E-100, Sub 73 dated November 28, 1994, the NCUC ordered North Carolina utilities to review the combined effects of existing economic development rates within the approved IRP process and file the results in its short-term action plan. The incremental load (demand) for which customers are receiving credits under economic development rates and/or self-generation deferral rates (Rider EC), as well as economic redevelopment rates (Rider ER) as of June 2020 is:

#### RIDER EC

14 MW for North Carolina  
8 MW for South Carolina

#### RIDER ER

0.3 MW for North Carolina  
0 MW for South Carolina





# WESTERN CAROLINAS MODERNIZATION PLAN (WCMP)



## APPENDIX N: WESTERN CAROLINAS MODERNIZATION PLAN (WCMP)

The Western Carolinas Modernization Plan (WCMP) is often viewed as a collection of investments:

- New combined cycle power plant (in-service)
- Retirement of existing coal-fired power plant (demolition is underway)
- Transmission improvements (many improvements complete)
- At least 15 megawatts of solar (progress made)
- At least 5 megawatts storage (significant progress made)

These investments are critical to ensuring a cleaner and smarter energy future for Duke Energy Progress – West Region (DEP-West). But, the cornerstone of the WCMP's success is its community and stakeholder engagement.

This deliberate and purposeful engagement began in 2016 when a group of local leaders, representing the City of Asheville, Buncombe County and Duke Energy, attended the Rocky Mountain Institute's eLab Accelerator. This immersive experience started to create a foundation of trust and helped outline a wholistic community engagement effort to increase demand-side management, energy efficiency and distributed energy resources locally.

From this grew the Energy Innovation Task Force (EITF). The EITF was formed in 2016 and comprised of a diverse group of community leaders to:

- Avoid or delay the construction of the planned contingent combustion turbine (CT).
- Transition DEP-West to a smarter, cleaner and affordable energy future.

The co-conveners (City of Asheville, Buncombe County and Duke Energy Progress) then engaged Rocky Mountain Institute as a key partner early in the process to provide analytical support. Because of their participation and expertise, the company knows more about how customers in DEP-West use electricity than ever before. Their work also narrowed the focus on areas for the group to focus – primarily heating system efficiency. This work extended through 2017.

The research of Rocky Mountain Institute also identified the current lack of automated-metering infrastructure (AMI) in the region as a barrier to the effort's overall success. AMI deployment is now

complete in DEP-West.

2018 was a pivotal year for the work of the Energy Innovation Task Force. This was when the group's 18-months of planning and analysis were put into action.

A critical milestone for the Energy Innovation Task Force was the launch of the Blue Horizons Project in March of 2018. This brand was created through community conversations facilitated by the Knoxville-based Sustainability marketing firm – The Shelton Group.

The Blue Horizons Project<sup>1</sup> is the brand associated with the community movement around energy efficiency, demand-side management, renewables and low-income weatherization locally. The primary gateway for customers to interact with Blue Horizons Project is a user-friendly website that directs customers to Duke Energy programs, local governmental initiatives and/or non-profit energy efficiency and weatherization opportunities.

Their work, along with canvassing by Duke Energy, helped expand the DSM program, EnergyWise<sup>SM</sup>. In 2016, when the Energy Innovation Task Force was formed, 7,183 DEP-West customers were enrolled in the program. As of August 13, 2018, 11,329 customers are enrolled in winter EnergyWise<sup>SM</sup> programs. Customer participation in this goal specifically addresses reductions in peak demand. In 2019, the focus was to grow participation in multi-family participation in EnergyWise<sup>SM</sup>.

Both the City of Asheville and Buncombe County have made sizable investments to advance the work of the Blue Horizons Project for building audits, staff support and other direct investments in low-income weatherization.

Through this community collaboration in DEP-West, specifically Buncombe County, the contingent CT has been pushed out beyond the horizon of this 15-year planning analysis. This was a significant and celebrated milestone in the community's work.

In 2019, the initial work of the EITF and Blue Horizons Project started to shift from defining the problem, to enabling broader support for larger, community-driven goals. The co-conveners of the EITF worked to redefine the future goal and purpose of the task force. To that end, the EITF has been

<sup>1</sup> <https://www.bluehorizonsproject.com>.

recast as the Blue Horizons Project Community Council (BHPCC). The purpose of this council will be to drive behavior and investments that help achieve the community renewable-energy goal.

In late 2018, both the City of Asheville and Buncombe County passed 100 percent clean/renewable energy goals. The goals require that both the City and County achieve the 100 percent targets for operations by 2030, and for all homes and businesses by 2042. The original conveners all agree that a continued commitment and partnership among the City, County, and Duke Energy is critical to enable success of these very ambitious local goals.

One area of focus is to fully leverage purposeful and deliberate investments in advanced and evolving technologies to help advance these lofty community goals. The Technology Working Group, a subcommittee of the Energy Innovation Task Force, has been meeting regularly for more than three years to look for cost-effective options for deployment of solar, battery storage, AMI, cold-climate heat pumps and other technologies. Their work has resulted in efforts to:

- Support and enable DEP-West's first ever microgrid (solar and battery) on Mt. Sterling in the Great Smoky Mountains National Park. (complete and in service)
- Advocate for and support a grid connected microgrid (solar and battery) to serve the Town of Hot Springs, should their radial feed go out. (initial construction is underway)
- Commit to at least 19 MW of battery storage in the region. A list of project updates is below:
  - Mt. Sterling Microgrid (Docket No. E-2, Sub 1127)
    - Haywood County
    - Approximate Capacity – 10 kW Solar PV and 95 kWh Battery Storage Facility
    - NCUC Order Granting CPCN – April 2017
    - Completion Date – May 2017
  - Asheville – Rock Hill Battery
    - Buncombe County
    - Sited at utility-owned substation
    - Approximate Capacity – 9 MW Battery Storage Facility
    - Completion Date – June 2020

- Hot Springs Microgrid (Docket No. E-2, Sub 1185)
  - Madison County
  - Approximate Capacity – 2 MW Solar PV and 4 MW Battery Storage Facility
  - NCUC Order Granting CPCN – May 2019
  - Anticipated In-Service Date – 2020
- Woodfin Solar
  - Buncombe County
  - Approximate Capacity – 4 to 5 MW Solar PV
  - CPCN Filed – July 2020
  - Anticipated In-Service Date – 2021
- Riverside Battery
  - Buncombe County
  - Sited at utility-owned substation
  - Approximate Capacity – 5 MW Battery Storage Facility
  - Anticipated In-Service Date – 2021
- Asheville Plant Solar and Battery
  - Buncombe County
  - Sited at utility-owned CC plant
  - Approximate Capacity – 9 to 10 MW Solar PV and 17 to 18 MW Battery Storage Facility
  - Anticipated In-Service Date – 2024
- Develop a pilot for cold-climate heat pump. This technology would operate more efficiently in the DEP-West region than other heat pump technologies.
- Partner with Buncombe County to site, design and build a large solar farm at the retired Buncombe County Landfill. (CPCN filed in July 2020)
- Enable an external pilot group for the real-time AMI usage app.

What makes the WCMP special is the engagement and community-centered approach to increasing participation in EE/DSM, making deliberate and strategic investments in technology, and supporting low-income customers with weatherization. Although collaboration with the DEP-West community



has yielded strong results, the efforts to transition the region to a smarter, cleaner and affordable energy future for customers continues.



## CROSS REFERENCE



Corrected 11.06.2020

**TABLE O-1**  
**CROSS REFERENCE - NC R8-60 REQUIREMENTS**

REQUIREMENT	REFERENCE	LOCATION
15-year Forecast of Load, Capacity and Reserves	NC R8-60 (c) 1	Chapter 3 Appendix C
Comprehensive analysis of all resource options	NC R8-60 (c) 2	Chapter 8 Chapter 12 Appendix A Appendix G
Assessment of Purchased Power	NC R8-60 (d)	Chapter 12 Appendix A Appendix J Attachment II
Assessment of Alternative Supply-Side Energy Resources	NC R8-60 (e)	Chapter 8 Appendix G
Assessment of Demand-Side Management	NC R8-60 (f)	Chapter 4 Appendix D Attachment V
Evaluation of Resource Options	NC R8-60 (g)	Chapter 5 Chapter 8 Appendix A Appendix D Appendix G
Short-Term Action Plan	NC R8-60 (h) 3	Chapter 14
REPS Compliance Plan	NC R8-60 (h) 4	Attachment I
Forecasts of Load, Supply-Side Resources, and Demand-Side Resources <ul style="list-style-type: none"> <li>* 10-year History of Customers and Energy Sales</li> <li>* 15-year Forecast w &amp; w/o Energy Efficiency</li> <li>* Description of Supply-Side Resources</li> </ul>	NC R8-60 (i) 1(i) NC R8-60 (i) 1(ii) NC R8-60 (i) 1(iii)	Chapter 3 Chapter 4 Appendix C Appendix D Attachment V

**TABLE O-1**  
**CROSS REFERENCE - NC R8-60 REQUIREMENTS (CONT.)**

REQUIREMENT	REFERENCE	LOCATION
Generating Facilities * Existing Generation * Planned Generation * Non-Utility Generation	NC R8-60 (i) 2(i) NC R8-60 (i) 2(ii) NC R8-60 (i) 2(iii)	Chapter 2 Chapter 12 Appendix B Appendix J
Reserve Margins	NC R8-60 (i) 3	Chapter 9 Chapter 12 Attachment III
Wholesale Contracts for the Purchase and Sale of Power * Wholesale Purchased Power Contracts * Request for Proposal * Wholesale Power Sales Contracts	NC R8-60 (i) 4(i) NC R8-60 (i) 4(ii) NC R8-60 (i) 4(iii)	Chapter 12 Chapter 14 Appendix A Appendix J
Transmission Facilities	NC R8-60 (i) 5	Chapter 7 Appendix L
Energy Efficiency and Demand-Side Management * Existing Programs * Future Programs * Rejected Programs * Consumer Education Programs	NC R8-60 (i) 6(i) NC R8-60 (i) 6(ii) NC R8-60 (i) 4(iii) NC R8-60 (i) 4(iv)	Chapter 4 Appendix D Attachment V
Assessment of Alternative Supply-Side Energy Resources * Current and Future Alternative Supply-Side Resources * Rejected Alternative Supply-Side Resources	NC R8-60 (i) 7(i) NC R8-60 (i) 7(ii)	Chapter 8 Appendix A Appendix G
Evaluation of Resource Options (Quantitative Analysis)	NC R8-60 (i) 8	Appendix A
Levelized Bus-bar Costs	NC R8-60 (i) 9	Appendix G
Smart Grid Impacts	NC R8-60 (i) 10	Appendix D
Legislative and Regulatory Issues		Appendix I
Greenhouse Gas Reduction Compliance Plan		Chapter 16 Appendix A
Other Information (Economic Development)		Appendix M
NCUC Subsequent Orders		Table O-3

**TABLE O-2**  
**CROSS REFERENCE – SC ACT 62 REQUIREMENTS**

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Each electrical utility must submit its integrated resource plan to the commission. The integrated resource plan must be posted on the electrical utility's website and on the commission's website.	Part (C)(2)	Post - filing
a long-term forecast of the utility's sales and peak demand under various reasonable scenarios;	Part (C)(2)	Chapter 3 Appendix A Appendix C
The type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;	Part (C)(2)	Chapter 8 Appendix A Appendix F Appendix G
projected energy purchased or produced by the utility from a renewable energy resource;	Part (C)(2)	Chapter 5 Chapter 12 Appendix A Appendix E Appendix J Appendix N (DEP)
a summary of the electrical transmission investments planned by the utility;	Part (C)(2)	Chapter 7 Appendix A Appendix L

**TABLE O-2**  
**CROSS REFERENCE – SC ACT 62 REQUIREMENTS (CONT.)**

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following: (i)customer energy efficiency and demand response programs; (ii)facility retirement assumptions; and (iii)sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;	Part (C)(2)	Chapter 3 Chapter 4 Chapter 12 Appendix A Appendix B Appendix C Appendix D Appendix I
data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;	Part (C)(2)	Chapter 2 Appendix B
plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan	Part (C)(2)	Chapter 7 Chapter 12 Chapter 13 Chapter 14 Chapter 15 Chapter 16 Appendix A



**TABLE O-2**  
**CROSS REFERENCE – SC ACT 62 REQUIREMENTS (CONT.)**

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs	Part (C)(2)	Chapter 7 Chapter 8 Chapter 12 Chapter 13 Chapter 14 Chapter 15 Chapter 16 Appendix A Appendix G
a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.	Part (C)(2)	Chapter 3 Chapter 4 Appendix C Appendix D
An integrated resource plan may include distribution resource plans or integrated system operation plans.	Part (C)(2)	Chapter 7 Chapter 11 Chapter 15 Appendix A Appendix L

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The two Base Case Plans (i.e. Base CO2 Future and Base No CO2 Future) ... encourages the Companies to carry forward both alternatives for their next IRPs due for 2020.”	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 12 Appendix A
<p>DEC and DEP present one or more alternative resource portfolios which show that the remainder of each Company’s existing coal-fired generating units are retired by the earliest practicable date.</p> <p>The “earliest practicable date” shall be identified based on reasonable assumptions and best available current knowledge concerning the implementation considerations and challenges identified.</p> <p>In the IRPs the Companies shall explicitly identify all material assumptions, the procedures used to validate such assumptions, and all material sensitivities relating to those assumptions.</p> <p>The Companies shall include an analysis that compares the alternative scenario(s) to the Base Case with respect to resource adequacy, long-term system costs, and operational and environmental performance.</p>	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 11 Appendix A Appendix I

**TABLE O-3**
**CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)**

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
<p>The Commission expects that the “earliest practicable date” chosen by the Companies when developing their alternative portfolio(s) and the replacement resources included in the portfolio(s) should reflect the transmission and distribution infrastructure investments that will be required to make a successful transition.</p> <p>The Companies should also attempt to identify – with as much specificity as is possible in the circumstances - all major transmission and distribution upgrades that will be required to support the alternative resource portfolio(s) along with the best current estimate of costs of constructing and operating such upgrades.</p>	<p>E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20</p>	<p>Chapter 7 Chapter 11 Appendix A Appendix L</p>
<p>The Companies should note that the directive in this order supplements and does not supersede the directive in the Commission’s August 27, 2019 Order in this docket (at p. 31), requiring that the Companies in preparing and modeling their Base Case plans remove any assumption that existing coal-fired units will be operated for the remainder of their depreciable lives and, instead, include such existing assets in the Base Case resource portfolio only if warranted under least cost planning principles.</p> <p>In this Order the Commission’s directive that the Companies present one or more “earliest practicable date” retirement portfolios is not constrained by least cost principles, and the Companies will be expected to discuss cost differences, if any, between such alternatives portfolios and the resource portfolios selected for their Base Cases.</p>	<p>E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20 E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20</p>	<p>Chapter 11 Appendix A</p>

**TABLE O-3**  
**CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)**

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Updated resource adequacy studies be filed along with the Companies' 2020 IRPs, together with all supporting exhibits, attachments and appendices subject to such confidentiality designations as the Companies deem warranted.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	IRP Filing Letters Chapter 9 Attachment III
In documenting the updated Resource Adequacy Study for 2020, the Companies should provide additional detail and support for both the study inputs and outputs.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The Commission will direct DEC and DEP to more fully explain and detail the study results.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The updated Resource Adequacy Study should provide additional clarity around outputs... At a minimum the Commission finds it helpful for results to be displayed in a graphic that clearly shows the various components to the Total System Costs such as included in the "Bathtub Curves."	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III
The Commission directs the updated Resource Adequacy studies to address the sensitivity of modeling inputs such as Equivalent Forced Outage Rates (EFOR).	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 9 Attachment III

**TABLE O-3**  
**CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)**

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
The Companies to continue to involve stakeholders in a meaningful way as the ISOP process advances. In particular, the Commission recognizes that there could be significant benefits to involving North Carolina’s electric membership cooperatives and municipally owned and operated electric utilities in this effort.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Executive Summary Chapter 15
The 2020 IRPs should continue to report on the progress of the ISOP effort. As a minimum, the IRPs should communicate with some specificity the project plan and dates for the ISOP effort. In addition, the Commission will direct the utilities to discuss the expected outputs of the ISOP process and how they will be utilized in the IRP process.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 15
The Commission determines that the “First Resource Need” section of DEC’s and DEP’s 2019 IRPs is an appropriate output of the integrated resource planning processes and adequate to support future avoided cost calculations.	E-100, Sub 157, ORDER ACCEPTING FILING OF 2019 UPDATE REPORTS AND ACCEPTING 2019 REPS COMPLIANCE PLANS, dated 4/6/20	Chapter 13
Demonstrate assessments of the benefits of purchased power solicitations, alternative supply side resources, potential DSM/EE programs, and a comprehensive set of potential resource options and combinations of resource options, as required by Commission Rule R8-60(d), (e), (f) and (g), including:	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 3 Chapter 4 Chapter 8 Chapter 12 Appendix A Appendix D Appendix G Appendix J

**TABLE O-3**  
**CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)**

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
A detailed discussion and work plan for how Duke plans to address the 1,200 MW of expiring purchased power contracts at DEP and 124 MW at DEC.	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 12 Chapter 14 Appendix A Appendix J
A discussion of the following statement: “The Companies’ analysis of their capacity and energy needs focuses on new resource selection while failing to evaluate other possible futures for existing resources. As part of the development of the IRPs, the Companies conducted a quantitative analysis of the resource options available to meet customers’ future energy needs. This analysis intended to produce a base case through a least cost analysis where each company’s system was optimized independently. However, the modeling exercise fails to consider whether existing resources can be cost effectively replaced with new resources. Therefore, Duke has not performed a least-cost analysis to design its recommended plans.”	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Chapter 12 Chapter 16 Appendix A
A stand-alone analysis of the cost effectiveness of a substantial increase in EE and DSM, rather than the combined modeling of EE and high renewables included in DEC’s and DEP’s Portfolio 5 in their 2018 IRPs.	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Appendix A Appendix D



**TABLE O-3**  
**CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)**

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Provide a discussion of the advantages and disadvantages of periodically issuing “all resources” RFPs in order to evaluate least-cost resources (both existing and new) needed to serve load	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Include information, analyses, and modeling regarding economic retirement of coal-fired units	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
Model continued operation under least cost principles in competition with alternative new resources	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A
If continued operation until fully depreciated is least cost alternative, shall separately model an alternative scenario premised on advanced retirement of one or more of such units (including an analysis of the difference in cost from the base case and preferred case scenarios.)	E-100, Sub 157, Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses, dated 8/27/19, Appendix A	Chapter 11 Appendix A

**TABLE O-3**  
**CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)**

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Future IRP filings by all IOUs shall continue to include a detailed explanation of the basis and justification for the appropriateness of the level of the respective utility's projected reserve margins.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 4	Chapter 9 Attachment III
Future IRP filings by all IOUs shall continue to include a copy of the most recently completed FERC Form 715, including all attachments and exhibits.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 5	Filed Under Seal
Future IRP filings by all IOUs shall continue to: (1) provide the amount of load and projected load growth for each wholesale customer under contract on a year-by-year basis through the terms of the current contract, segregate actual and projected growth rates of retail and wholesale loads, and explain any difference in actual and projected growth rates between retail and wholesale loads, and (2) for any amount of undesignated load, detail each potential customer's current supply arrangements and explain the basis for the utility's reasonable expectation for serving each such customer.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 6 E-100, Sub 1118 and Sub 124, Order Approving Integrated Resource Plans and REPS Compliance Plans (2008-09), dated 8/10/10, ordering paragraph 6	Chapter 3 Appendix C
IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and EE between successive IRPs, and evaluate and discuss any changes on a program-specific basis. Any issues impacting program deployment should be thoroughly explained and quantified in future IRPs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 7	Appendix D

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
Each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.	E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 8 E-100, Sub 128, Order Approving 2011 Annual Updates to 2010 IRPs and 2011 REPS Compliance Plans, dated 5/30/12, ordering paragraph 9	Appendix D Attachment V
All IOUs shall include in future IRPs a full discussion of the drivers of each class' load forecast, including new or changed demand of a particular sector or sub-group.	E-100, Sub 141, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/26/15, ordering paragraph 9 E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 9 E-100, Sub 133, Order Denying Rulemaking Petition (Allocation Methods), dated 10/30/12, ordering paragraph 4	Chapter 3 Appendix C

**TABLE O-3**  
**CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)**

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
<p>Future IRP filings by DEP and DEC shall continue to provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.</p>	<p>E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 14  E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 14</p>	<p>Chapter 5  Appendix E  Appendix K</p>
<p>Duke plans to diligently review the business case for relicensing existing nuclear units, and if relicensing is in the best interest of customers, pursue second license renewal.</p>	<p>No new reporting requirements, but NCUC stated its expectation that Duke would make additional changes to future IRPs as discussed in Duke's 4/20/15 reply comments (p. 7) in E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15 (p. 39)</p>	<p>Chapter 10</p>

TABLE O-3

CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
<p>Duke will include Li-ion battery storage technology in the economic supply-side screening process as part of the IRP.</p>	<p>No new reporting requirements, but NCUC stated its expectation that Duke would make additional changes to future IRPs as discussed in Duke's 4/20/15 reply comments (p. 19) in E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15 (p. 39)</p>	<p>Chapter 6 Chapter 8 Chapter 12 Appendix A Appendix G Appendix H</p>
<p>DEP will incorporate into future IRPs any demand and energy savings resulting from the Energy Efficiency Education Program, My Home Energy Report Program, Multi-Family Energy Efficiency Program, Small Business Energy Saver Program, and Residential New Construction Program.</p>	<p>E-2, Sub 1060, Order Approving Program, dated 12/18/14, p. 2 E-2, Sub 989, Order Approving Program, dated 12/18/14, p. 3 E-2, Sub 1059, Order Approving Program, dated 12/18/14, p. 2 E-2, Sub 1022, Order Approving Program, dated 11/5/12, footnote 2 (Small Business Energy Saver) E-2, Sub 1021, Order Approving Program, dated 10/2/12, footnote 3 (Residential New Construction Program)</p>	<p>Appendix D</p>

**TABLE O-3**  
**CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)**

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
<p>To the extent an IOU selects a preferred resource scenario based on fuel diversity, the IOU should provide additional support for its decision based on the costs and benefits of alternatives to achieve the same goals.</p>	<p>E-100, Sub 141, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 6/26/15, ordering paragraph 13  E-100, Sub 137, Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, dated 6/30/14, ordering paragraph 13  E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 16</p>	<p>Chapter 8  Appendix A  Appendix F  Appendix G</p>
<p>DEC and DEP should consider additional resource scenarios that include larger amounts of renewable energy resources similar to DNCP's Renewable Plan, and to the extent those scenarios are not selected, discuss why the scenario was not selected.</p>	<p>E-100, Sub 137, Order Approving Integrated Resource Plans and REPS Compliance Plans, dated 10/14/13, ordering paragraph 15</p>	<p>Chapter 5  Appendix A  Appendix E  Appendix N (DEP)</p>
<p>DEP, DEC and DNCP shall annually review their REPS compliance plans from four years earlier and disclose any redacted information that is no longer a trade secret.</p>	<p>E-100, Sub 137, Order Granting in Part and Denying in Part Motion for Disclosure, dated 6/3/13, ordering paragraph 3</p>	<p>Attachment I</p>



**TABLE O-3**  
**CROSS REFERENCE – NCUC SUBSEQUENT ORDER REQUIREMENTS (CONT.)**

REQUIREMENT	SOURCE (DOCKET AND ORDER DATE)	LOCATION
[2013] Duke shall show the peak demand and energy savings impacts of each measure/option in the Program separately from each other, and separately from the impacts of its other existing PowerShare DSM program options in its future IRP and DSM filings, and in its evaluation, measurement, and verification reports for each measure of the Program.	E-7, Sub 953, Order Approving Amended Program, dated 1/24/13, ordering paragraph 4 (PowerShare Call Option Nonresidential Load and Curtailment Program)	Appendix D
Each utility shall include in each biennial report potential impacts of smart grid technology on resource planning and load forecasting: a present and five-year outlook – see R8-60(i)(10).	E-100, Sub 126, Order Amending Commission Rule R8-60 and Adopting Commission Rule R8-60.1, dated 4/11/12	Chapter 14 Appendix D

## GLOSSARY OF TERMS

<b>10 CFR</b>	Title 10 of the Code of Federal Regulations
<b>AC or A/C</b>	Alternating Current
<b>ACE</b>	Affordable Clean Energy
<b>ACP</b>	Atlantic Coast Pipeline
<b>ACT 62</b>	South Carolina Act 62
<b>ADP</b>	Advanced Distribution Planning
<b>AEO</b>	Annual Energy Outlook
<b>AGC</b>	Automatic Generator Control
<b>AMI</b>	Advanced Metering Infrastructure
<b>APS</b>	Arizona Public Service Electric
<b>ARP</b>	Acid Rain Program
<b>ARPA-E</b>	Advanced Resource Projects Agency-Energy
<b>ASOS</b>	National Weather Service Automated Surface Observing System
<b>BHPCC</b>	Blue Horizons Project Community Council (DEP)
<b>BCFD</b>	Billion Cubic Feet Per Day
<b>BFB</b>	Bubbling Fluidized Bed
<b>BOEM</b>	Bureau of Ocean Energy Management
<b>BYOT</b>	Bring Your Own Thermostat
<b>CAES</b>	Compressed Air Energy Storage
<b>CAIR</b>	Clean Air Interstate Rule
<b>CAMA</b>	North Carolina Coal Ash Management Act of 2014
<b>CAMR</b>	Clean Air Mercury Rule
<b>CAPP</b>	Central Appalachian Coal
<b>CC</b>	Combined Cycle
<b>CCR</b>	Coal Combustion Residuals Rule
<b>CCS</b>	Carbon Capture and Sequestration (Carbon Capture and Storage)
<b>CCUS</b>	Carbon Capture, Utilization and Storage
<b>CEPCN</b>	Certificate of Environmental Compatibility and Public Convenience and Necessity (SC)
<b>CEP</b>	Comprehensive Energy Planning
<b>CES</b>	Clean Electricity Standard
<b>CFL</b>	Compact Fluorescent Light bulbs
<b>CHP</b>	Combined Heat and Power

## GLOSSARY OF TERMS (CONT.)

CO <sub>2</sub>	Carbon Dioxide
COD	Commercial Operation Date
COL	Combined Construction and Operating License
COVID-19	Coronavirus 2019
COWICS	Carolinas Offshore Wind Integration Case Study
CPCN	Certificate of Public Convenience and Necessity (NC)
CPP	Clean Power Plan
CPRE	Competitive Procurement of Renewable Energy
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
CVR	Conservation Voltage Reduction
CWA	Clean Water Act
DC	Direct Current
DCA	Design Certification Application
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEI	Duke Energy Indiana
DEK	Duke Energy Kentucky
DEP	Duke Energy Progress
DER	Distributed Energy Resource
DER	Duke Energy Renewables
DESC	Dominion Energy South Carolina, Inc. (formerly SCE&G)
DIY	Do It Yourself
DMS	Distribution Management System
DoD	Depth of Discharge
DOE	Department of Energy
DOJ	Department of Justice
DOM	Dominion Zone within PJM RTO
DR	Demand Response
DSCADA	Distribution Supervisory Control and Data Acquisition
DSDR	Distribution System Demand Response Program
DSM	Demand-Side Management

## GLOSSARY OF TERMS (CONT.)

<b>EC or Rider EC</b>	Receiving Credits under Economic Development Rates and/or Self-Generation deferral rate
<b>EE</b>	Energy Efficiency
<b>EGU</b>	Electric Generating Unit
<b>EIA</b>	Energy Information Administration
<b>EITF</b>	Energy Innovation Task Force
<b>ELCC</b>	Effective Load Carrying Capability
<b>ELG Rule</b>	Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category
<b>EPA</b>	Environmental Protection Agency
<b>EPC</b>	Engineering, Procurement, and Construction Contractors
<b>EPRI</b>	Electric Power Research Institute
<b>ER or Rider ER</b>	Receiving Credits under Economic Re-Development Rates
<b>ESG</b>	Environmental, Social and Corporate Governance
<b>ET</b>	Electric Transportation
<b>EVs</b>	Electric Vehicles
<b>FERC</b>	Federal Energy Regulatory Commission
<b>FGD</b>	Flue Gas Desulfurization
<b>FIP</b>	Federal Implementation Plan
<b>FLG</b>	Federal Loan Guarantee
<b>FPS</b>	Feet Per Second
<b>FRCC</b>	Florida Reliability Coordinating Council, Inc.
<b>FSO</b>	Fuels and System Optimization
<b>FT Solar</b>	Fixed-tilt Solar
<b>GALL-SLR</b>	Generic Aging Lessons Learned for Subsequent License Renewal
<b>GA-AL-SC</b>	Georgia-Alabama-South Carolina
<b>GHG</b>	Greenhouse Gas
<b>GIP</b>	Grid Improvement Plan
<b>GTI</b>	Gas Technology Institute
<b>GW</b>	Gigawatt
<b>GWh</b>	Gigawatt-hour
<b>HAP</b>	Hazardous Air Pollutants
<b>HB 589</b>	North Carolina House Bill 589
<b>HRSG</b>	Heat Recovery Steam Generator

## GLOSSARY OF TERMS (CONT.)

<b>HVAC</b>	Heating, Ventilation and Air Conditioning
<b>IA</b>	Interconnection Agreement
<b>IESO</b>	Independent Electricity System Operator
<b>IGCC</b>	Integrated Gasification Combined Cycle
<b>ILB</b>	Illinois Basin
<b>ILR</b>	Inverter Load Ratios
<b>IPI</b>	Industrial Production Index
<b>IRP</b>	Integrated Resource Plan
<b>IS</b>	Interruptible Service
<b>ISO-NE</b>	ISO New England, Inc.
<b>ISOP</b>	Integrated Systems and Operations Planning
<b>IT</b>	Information Technologies
<b>ITC</b>	Federal Investment Tax Credit
<b>IVVC</b>	Integrated Volt-Var Control
<b>JDA</b>	Joint Dispatch Agreement
<b>kW</b>	Kilowatt
<b>kWh</b>	Kilowatt-hour
<b>LCOE</b>	Levelized Cost of Energy
<b>LCR Table</b>	Load, Capacity, and Reserves Table
<b>LED</b>	Light Emitting Diodes
<b>LEED</b>	Leadership in Energy and Environmental Design
<b>LEO</b>	Legally Enforceable Obligation
<b>LFE</b>	Load Forecast Error
<b>Li-ION</b>	Lithium Ion
<b>LNG</b>	Liquefied Natural Gas
<b>LOLE</b>	Loss of Load Expectation
<b>LOLH</b>	Loss of Load Hours
<b>M&amp;V</b>	Measurement and Verification
<b>MACT</b>	Maximum Achievable Control Technology
<b>MATS</b>	Mercury and Air Toxics Standard
<b>MGD</b>	Million Gallons Per Day
<b>MISO</b>	Midcontinent Independent Operator

## GLOSSARY OF TERMS (CONT.)

<b>MPS</b>	Market Potential Study
<b>MMBtu</b>	Million British Thermal Units
<b>MW</b>	Megawatt
<b>MW AC</b>	Megawatt-Alternating Current
<b>MW DC</b>	Megawatt-Direct Current
<b>MWh</b>	Megawatt-hour
<b>MWh AC</b>	Megawatt-hour-Alternating Current
<b>MWh DC</b>	Megawatt-hour-Direct Current
<b>MyHER</b>	My Home Energy Report
<b>NAAQS</b>	National Ambient Air Quality Standards
<b>NAPP</b>	Northern Appalachian Coal
<b>NC</b>	North Carolina
<b>NC HB 589</b>	North Carolina House Bill 589
<b>NC REPS or REPS</b>	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
<b>NCCSA</b>	North Carolina Clean Smokestacks Act
<b>NCDAQ</b>	North Carolina Division of Air Quality
<b>NCDEQ</b>	North Carolina Division of Environmental Quality
<b>NCEMC</b>	North Carolina Electric Membership Corporation
<b>NCMPA1</b>	North Carolina Municipal Power Agency #1
<b>NC REPS</b>	North Carolina Renewable Energy and Energy Efficiency Portfolio Standard
<b>NCTPC</b>	NC Transmission Planning Collaborative
<b>NCUC</b>	North Carolina Utilities Commission
<b>NEM</b>	Net Energy Metering
<b>NEMS</b>	National Energy Modeling Systems
<b>NERC</b>	North American Electric Reliability Corporation
<b>NERC RAPA</b>	Reliability and Performance Analysis
<b>NES</b>	Neighborhood Energy Saver
<b>NESHAP</b>	National Emission Standards for Hazardous Air Pollutants
<b>NET CONE</b>	Net Cost of New Entry
<b>NGCC</b>	Natural Gas Combined Cycle
<b>NO<sub>x</sub></b>	Nitrogen Oxide
<b>NPDES</b>	National Pollutant Discharge Elimination System



## GLOSSARY OF TERMS (CONT.)

<b>NRC</b>	Nuclear Regulatory Commission
<b>NREL</b>	National Renewable Energy Laboratory
<b>NSPS</b>	New Source Performance Standard
<b>NUG</b>	Non-Utility Generator
<b>NUREG</b>	Nuclear Regulatory Commission Regulation
<b>NYISO</b>	New York Independent System Operator
<b>NYMEX</b>	New York Mercantile Exchange
<b>O&amp;M</b>	Operating and Maintenance
<b>OATT</b>	Open Access Transmission Tariff
<b>PC</b>	Participant Cost Test
<b>PD</b>	Power Delivery
<b>PERFORM</b>	Performance-based Energy Resource Feedback, Optimization and Risk Management
<b>PEV</b>	Plug-In Electric Vehicles
<b>PHS</b>	Pumped Hydro Storage
<b>PJM</b>	PJM Interconnection, LLC
<b>PMPA</b>	Piedmont Municipal Power Agency
<b>PPA</b>	Purchase Power Agreement
<b>PPB</b>	Parts Per Billion
<b>PRB</b>	Powder River Basin
<b>PROSYM</b>	Production Cost Model
<b>PSCSC</b>	Public Service Commission of South Carolina
<b>PSD</b>	Prevention of Significant Deterioration
<b>PSH</b>	Pumped Storage Hydro
<b>PURPA</b>	Public Utility Regulatory Policies Act
<b>PV</b>	Photovoltaic
<b>PVDG</b>	Solar Photovoltaic Distributed Generation Program
<b>PVRR</b>	Present Value Revenue Requirement
<b>QF</b>	Qualifying Facility
<b>RCRA</b>	Resource Conservation Recovery Act
<b>REC</b>	Renewable Energy Certificate
<b>REPS or NC</b>	Renewable Energy and Energy Efficiency Portfolio Standard
<b>REPS</b>	

## GLOSSARY OF TERMS (CONT.)

RFP	Request for Proposal
RICE	Reciprocating Internal Combustion Engines
RIM	Rate Impact Measure
RPS	Renewable Portfolio Standard
RRP	Refrigerator Replacement Program
RTO	Regional Transmission Organization
RTR	Residential Risk and Technology Review
SAE	Statistical Adjusted End-Use Model
SAT Solar	Single-Axis Tracking Solar
SB 3 or NC SB 3	North Carolina Senate Bill 3
SC	South Carolina
SC Act 62	South Carolina Energy Freedom Act of 2018
SC DER or SC ACT 236	South Carolina Distributed Energy Resource Program
SC DER	South Carolina Distributed Energy Resources
SCR	Selective Catalytic Reduction
SEER	Seasonal Energy Efficiency Ratio
SEIA	Solar Energy Industries Association
SEPA (Ch. 15)	Smart Electric Power Alliance
SEPA (Ch. 2)	Southeastern Power Administration
SERC	SERC Reliability Corporation
SERVM	Strategic Energy Risk Valuation Model
SG	Standby Generation or Standby Generator Control
SIP	State Implementation Plan
SISC	Solar Integration Services Charge
SLR	Subsequent License Renewal
SMR	Small Modular Reactor
SO	System Optimizer
SO <sub>2</sub>	Sulfur Dioxide
SOC	State of Charge
SOG	Self-Optimizing Grid
SPM	Sequential Peaker Method

## GLOSSARY OF TERMS (CONT.)

<b>SRP – SLR</b>	Standard Review Plan for the Review of Subsequent License Renewal
<b>STAP</b>	Short-Term Action Plan
<b>STEO</b>	Short-Term Energy Outlook
<b>SVC</b>	Static Var Compressors
<b>T&amp;D</b>	Transmission & Distribution
<b>TAG</b>	Technology Assessment Guide
<b>TCFD</b>	Trillion Cubic Feet per Day
<b>Transco</b>	Transcontinental Pipeline
<b>The Company</b>	Duke Energy Progress
<b>The Plan</b>	Duke Energy Progress Annual Plan
<b>TRC</b>	Total Resource Cost
<b>TVA</b>	Tennessee Valley Authority
<b>UCT</b>	Utility Cost Test
<b>UEE</b>	Utility Energy Efficiency
<b>UNC</b>	University of North Carolina
<b>USCPC</b>	Ultra-Supercritical Pulverized Coal
<b>VACAR</b>	Virginia/Carolinas
<b>VAR</b>	Volt Ampere Reactive
<b>VCEA</b>	Virginia Clean Economy Act
<b>VVO</b>	Volt-Var Optimization
<b>WCMP</b>	Western Carolinas Modernization Project (DEP)
<b>WERP</b>	Weatherization and Equipment Replacement Program
<b>WIIN</b>	Water Infrastructure Improvement for the Nation Act
<b>ZELFR</b>	Zero – Emitting Load Following Resource



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